# 2006 INTEGRATED ENERGY POLICY REPORT UPDATE

Governor
Arnold Schwarzenegger

**CALIFORNIA ENERGY COMMISSION**

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# ABSTRACT

The *2006 Integrated Energy Policy Report Update* provides a midcourse review of two areas: Renewable Portfolio Standard activities and the potential relationship between sustainable land use planning, also called “smart growth,” and energy saving opportunities. The report discusses why California has made only minimal progress to date in meeting Renewable Portfolio Standard goals, identifies challenges the state faces in achieving those goals, and offers recommendations. It also details the lack of relationship between land use planning activities and energy concerns and offers recommendations for taking advantage of potential energy efficiencies that smart growth would offer.

**Key Words**
Renewable Portfolio Standard, RPS, renewable energy, distributed generation, transmission, energy infrastructure, smart growth, sustainable land use, land use, land use planning.

# PREFACE

As in previous proceedings, the 2007 Integrated Energy Policy Report Committee recognizes that close coordination with federal, state, and local agencies is needed to adequately identify and address critical energy infrastructure and related environmental challenges. In addition, input from state and local agencies is needed to develop the information and analyses that these agencies need to carry out their energy-related duties. This *2006 Integrated Energy Policy Report Update* reflects the input of stakeholders and federal, state, and local agencies that participated in this proceeding. The information gained from workshops and stakeholders was essential in developing the recommendations in this report.

The Committee would like to thank stakeholders for their participation and thoughtful contributions to the process.

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# EXECUTIVE SUMMARY

Senate Bill 1389 (Bowen and Sher), 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 reports the results of these assessments and forecasts every two years to the Governor, the Legislature, and the California public in the *Integrated Energy Policy Report*. In the alternate years, the Energy Commission prepares the *Integrated Energy Policy Report Update* to discuss the status of energy issues identified in the previous *Integrated Energy Policy Report* and to identify energy issues that may have emerged since that report was completed. This *2006 Integrated Energy Policy Report Update* fulfills the update requirement for 2006.

In the *2005 Integrated Energy Policy Report*, adopted on November 12, 2005, the Energy Commission recommended policies and actions to ensure adequate energy resources, reduce energy demand, develop a broad range of alternative energy resources, and improve the state's infrastructure.

The 2007 Integrated Energy Policy Report Committee (Committee) held a hearing on May 12, 2006, to receive comments on the proposed scope of the 2007 Integrated Energy Policy Report proceeding. At the hearing, parties provided the Committee with thoughtful oral and written input on the proposed scope. The Committee has considered these comments in revising the scope of the 2007 Integrated Energy Policy Report proceeding.

As an interim part of the 2007 Integrated Energy Policy Report proceeding, the *2006 Integrated Energy Policy Report Update* focuses on two topics: (1) the status of progress to meet Renewable Portfolio Standards goals to generate 20 percent of the state's electricity from renewable resources by 2010 and 33 percent by 2020; and (2) clean energy development and energy saving opportunities arising from sustainable land use planning.

Achieving the state's Renewable Portfolio Standard goals is an essential component of California's greenhouse gas emission reduction targets. The *2005 Integrated Energy Policy Report* concluded that statewide renewable procurement is not occurring at a pace that will reach Renewable Portfolio Standard goals by 2010 and, as a result, the process is in need of review and correction.

Land use decisions have a significant and long-lasting impact on California's energy use and infrastructure and, consequently, on its ability to achieve greenhouse gas emission reduction targets. The state should undertake an examination of current land use practices and potential policies to take advantage of the energy saving opportunities of sustainable land use planning.

Both of these topics address strategies to achieve California's greenhouse gas emission reduction targets, established by the Governor in Executive Order #S-3-05 and codified in Assembly Bill 32 (Nuñez), Chapter 488, Statutes of 2006. The Executive Order and Assembly Bill 32 commit the state to reduce greenhouse gas emissions to 2000 levels by 2010 and to 1990 levels by 2020.

A third key strategy for achieving the state's greenhouse gas emission reduction targets is increasing the penetration of alternative fuels in the transportation sector. The Energy Commission is currently working on a companion report, required by Assembly Bill 1007 (Pavley), Chapter 371, Statutes of 2005, that will examine the potential for greater use of alternative fuels in the state and recommend actions to achieve that potential. The results of this work will be incorporated in the *2007 Integrated Energy Policy Report*.

## Midcourse Review of the Renewable Portfolio Standard

The Energy Commission initiated a midcourse review of the Renewable Portfolio Standard program because the state did not appear to be on a trajectory to achieve the near-term goal of supplying 20 percent of the state's electricity needs with renewable energy by 2010 and the longer-term goal of 33 percent by 2020. California has achieved only minimal increases in renewable generation. Between 2002, the year in which the Renewable Portfolio Standard took effect, and 2005, the percentage of renewable energy in California's generation mix has remained nearly constant rather than increasing by at least 1 percent per year as required under the statute.

### *Slow Progress in Achieving Renewable Portfolio Standard Goals*

The investor-owned utilities, including Pacific Gas and Electric, Southern California Edison, and San Diego Gas and Electric, continue to affirm their commitment to the Renewable Portfolio Standard. They claim progress in achieving Renewable Portfolio Standard goals based on contracts they have entered into over the last few years for as much as 3,936 megawatts of renewable capacity. However, only 242 megawatts of those renewable contracts represent new facilities that are on line and delivering electricity today. To meet the goal of 20 percent by 2010, the investor-owned utilities, collectively, will need to add as much as 1,500 megawatts of eligible renewable generating capacity over the next four years beyond what is already under contract.

Unlike the Renewable Portfolio Standard program for investor-owned utilities, which is overseen by the California Public Utilities Commission and the Energy Commission, publicly owned utilities—which include municipal utilities and irrigation districts—are responsible for implementing and enforcing their own renewable standards. As a result, the progress of the state's publicly owned utilities toward achieving statewide Renewable Portfolio Standard goals is less clear. The state's two largest publicly owned utilities, the Los Angeles Department of Water and Power and the Sacramento

Municipal Utility District, have established targets of 20 percent by 2010 and 23 percent by 2011, respectively. To meet their share of the statewide goal of 20 percent by 2010, publicly owned utilities will need to increase the percentage of eligible renewables in their system mix more than two percentage points per year between now and 2010.

## *Barriers to Achieving Renewable Portfolio Standard Goals*

The Committee found five primary barriers to achieving the state's Renewable Portfolio Standard goals:

- Inadequate transmission infrastructure to connect remotely-located renewable resources.
- Uncertainty regarding whether projects with supplemental energy payment awards will be able to obtain project financing.
- Complexity and lack of transparency in the Renewable Portfolio Standard program implementation for investor-owned utilities.
- Insufficient attention to the possibility for contract failure and delay.
- Lack of progress in repowering aging wind facilities.

Achieving Renewable Portfolio Standard goals is hampered by the lack of adequate transmission to access important renewable resources in Tehachapi and the Imperial Valley. Several near-term transmission projects in the permitting process are experiencing delays. Disputes over the best plan for configuring transmission projects to allow the full build-out of Tehachapi resources have delayed progress in moving additional transmission projects into permitting. Finally, cost allocation issues have created uncertainty about cost recovery, delaying additional investments in renewable transmission.

Many stakeholders have raised concerns that supplemental energy payment awards under the current Renewable Portfolio Standard structure do not represent a financeable revenue stream, making it difficult for projects that require these funds to obtain the financing needed to move forward. While a significant amount of supplemental energy payment funding is available today, these funds are held in accounts from which the state has borrowed in the past for other purposes. Uncertainty about the availability of supplemental energy payments may make projects needing these awards unfinanceable. Because utilities are only required to pay up to the market price referent, insufficient or uncertain supplemental energy payment funding will reduce available renewables.

Program complexity and lack of transparency also remain significant barriers to the development of renewable resources in California. Investor-owned utilities select projects based on individual "least-cost, best-fit" methodologies that are not well understood by project bidders or by decision makers and may not adequately reflect state economic and environmental policy considerations. In addition, the process for setting the market price referent—used to determine the above-market costs of meeting the Renewable Portfolio Standard—is unclear, undermining public confidence in the awarding of public funds to further Renewable Portfolio Standard goals.

Utility procurement strategies have not yet sufficiently factored in the risk of contract erosion, creating additional uncertainty about the attainment of Renewable Portfolio Standard goals. Many projects with Renewable Portfolio Standard contracts have been delayed, and a number of them have been cancelled. In addition, several of the largest contracts rely on technologies not yet commercially proven at the scale envisioned, raising concerns about these contracts staying on course.

Finally, over the last several years utilities have made little progress in pursuing repowering of aging wind facilities that are already connected to the grid and that could provide additional renewable energy through the use of more modern and efficient technologies. This issue was discussed in more detail in the *2004 Integrated Energy Policy Report Update* and the *2005 Integrated Energy Policy Report* but is being revisited here because of the lack of progress.

## *Recommendations to Achieve the Near-Term Renewable Portfolio Standard Goal*

Although stakeholders acknowledge that problems exist with the Renewable Portfolio Standard structure, most parties recommend that the state not make wholesale changes to the program structure at this time. The Energy Commission, therefore, reluctantly recommends making no major changes to this structure now, but rather, working within the current protocols to meet the 2010 goals. However, the Energy Commission recommends that the state adopt revisions within this program structure to accelerate progress toward reaching the 2010 target and commit itself to less-inhibited evaluation of program designs to achieve the 2020 goal.

To address ongoing **transmission barriers** to renewable development, the Energy Commission recommends:

- The California Public Utilities Commission should expedite processing of Certification of Public Convenience and Necessity applications for renewable transmission projects including the Antelope Transmission Project and Sunrise Powerlink project.
- The state's energy agencies and municipal utilities should actively support the California Independent System Operator's proposal to the Federal Energy Regulatory Commission to develop a third category of transmission projects to accommodate renewable resource development.

To address problems with supplemental energy payment **uncertainty and financeability** in the Renewable Portfolio Standard program, the Energy Commission recommends:

- The Energy Commission and the California Public Utilities Commission should jointly alter the supplemental energy payment procedures to reduce the contracting complexity of projects requiring supplemental energy payments.

To address problems in **complexity and transparency** in the Renewable Portfolio Standard program, the Energy Commission recommends:

- The state should maintain the per-kilowatt-hour penalties for investor-owned utility non-compliance with Renewable Portfolio Standard goals consistent with California Public Utilities Decision 06-05-039, and eliminate the current per-utility cap on those penalties.
- The California Public Utilities Commission, working with the Energy Commission, should continue its efforts to make the Renewable Portfolio Standard process more open and transparent, requiring investor-owned utilities to clarify least-cost, best-fit criteria and their application in selecting projects.
- The natural gas price forecast used in determining the market price referent should be consistent with forecasts used in other procurement-related activities, including those used for energy efficiency programs. In addition, investor-owned utility methodologies for time of delivery factors should be standardized.
- The state should move away from stand-alone engineering calculations currently used in the market price referent to a portfolio approach. Also, the market price referent calculation should explicitly recognize the important value of renewable resources as both a hedge against future natural gas price volatility and a vital component of the state's greenhouse gas reduction strategy.
- Investor-owned utilities should be required either to accept all bilateral Renewable Portfolio Standard offers under the market price referent or document why such offers were not accepted. Such documentation is already required by California Public Utilities Commission Decision 06-05-039 for Renewable Portfolio Standard solicitations but it is not clear whether this requirement also applies to bilateral Renewable Portfolio Standard offers.
- The state should evaluate the ramifications of providing a higher rate of return for renewable energy facilities to make them more financially attractive.

To address **contract failure risk and ensure timely completion** of projects with Renewable Portfolio Standard contracts, the Energy Commission recommends:

- Utilities should be required to procure a contract risk reserve margin of 30 percent or more beyond what is needed to meet the 20 percent by 2010 renewable goals, and the state should more clearly define how penalties will be applied in the case of contract failure.
- In the semi-annual compliance reports already required by the California Public Utilities Commission under Decision 06-05-039, utilities should report on project development milestones consistent with those required by the Energy Commission for projects receiving supplemental energy payments.
- The Energy Commission should provide project assistance for renewable developers similar to the "Green Team" approach established during the electricity crisis.

To address lack of progress in **wind repowering,** the Energy Commission recommends:

- The state's energy agencies should evaluate possible incentives to encourage repowering of aging wind facilities to boost renewable generation from these prime sites while reducing avian impacts.

## *Recommendation to Achieve Long-Term Renewable Portfolio Standard Goals*

California must accelerate its pace of renewable development if it is to meet its long-term Renewable Portfolio Standard goal of generating 33 percent of the state's electricity from renewable resources by 2020, as recommended by Governor Schwarzenegger, the Energy Commission, and the California Public Utilities Commission. This long-term goal is essential to meeting the state's greenhouse gas emission reduction goals and to achieve other benefits associated with the use of renewable energy.

The Energy Commission recommends that the following issues be further analyzed to help shape the achievement of post-2010 Renewable Portfolio Standard goals:

- The relationship between renewable energy, renewable energy certificates, and carbon emission trading in implementing greenhouse gas reductions called for in Assembly Bill 32.
- Alternative structures to meet 2020 Renewable Portfolio Standard goals, including whether revised system benefit charge mechanisms or feed-in tariffs would spur additional renewable development.
- Changing or eliminating the market price referent/supplemental energy payment award structure.

## The Relationship Between Energy and Land Use

Experts expect California's population to grow by 20 million people between 2000 and 2050. Such growth will severely tax already constrained energy resources and the associated infrastructure and challenge the state's ability to provide the energy that new communities, homes, schools, industry, and other workplaces will require. This rapidly advancing scenario shines a spotlight on a relationship that until now has received little attention: the profound impact of land use decisions on every aspect of energy.

The burden that a burgeoning population will place on energy supply and infrastructure suggests a need for a fundamental shift in approaches to land use and development. The state needs to investigate approaches that go beyond decreasing transportation fuel use and relieving congestion to approaches that can serve as a nexus for developing distributed renewable generation and efficient transportation in communities to help California meet its statewide energy and climate change goals.

Probably the single largest opportunity to meet those goals resides with "smart growth." Smart growth refers to the application of specific development principles to make prudent use of resources and create genial, low-impact communities through enlightened design and layout. Assuming that all new U.S. housing is smart growth, the total nationwide savings after 10 years, based on a projected level of 24.3 million housing starts from 2005 to 2020, would be in the range of 977 trillion miles of travel reduced; 5.69 trillion Btu saved; 49.5 billion gallons of gasoline saved; 1.18 billion barrels of oil saved; 595 million metric tons of $CO_2$ emissions reduced; and $2.18 trillion savings.

The Governor's Climate Action Team identified smart land use and intelligent transportation systems as major elements of a unified program to meet the goals of Assembly Bill 32. In the *Climate Action Report*, smart land use and intelligent transportation systems are projected to result in reductions of 1.77 million metric tons $CO_2$ equivalent by 2010 and 14.5 million metric tons by 2020. These projected reductions represent a major portion of the total greenhouse gas reduction goal.

### *Current Land Use Planning and Development Practices Fail to Address Energy*

Organized land use planning is largely a relic of post-World War II sprawl to accommodate the "baby boom" and a healthy post-war economy. State laws outline the framework within which land use authority is to be exercised; however, local government is the entity primarily charged with land use decisions. As the official planning document for a community, the general plan is a statement of development policies that sets forth objectives, principles, standards, and proposals. The plan is required by law to have seven elements: land use, circulation, housing, conservation, open space, noise, and safety. No specific state mandate requires that a general plan include an energy element, and only some 10 percent of California's general plans do so.

The lack of energy consideration on the part of land use decision-making authorities and developers in their planning processes today is apparent. Although some exceptions exist, most energy considerations of current land use planning practices relate exclusively to transportation issues: reducing the number of vehicle miles traveled, thus reducing fuel consumption, air pollution, and roadway congestion. Specifically, planners tend to focus on increasing density, changing zoning to allow for mixed use development, and building near transit stations to achieve these aims. The host of related support services and infrastructure—fueling stations, transmission lines, power plants and pipelines—and the potential for distributed renewable generation and energy efficient design are rarely considered in planning uses for land parcels.

Land use practices are slowly changing as a result of new efforts to create smart growth and include energy considerations in land use. The state took a major step toward smart growth with the passage of Assembly Bill 857 (Wiggins), Chapter 1016, Statutes of 2002, which laid out three planning priorities: promote infill development and social equity in existing communities; protect and conserve environmental and agricultural resources; and achieve more efficient use of land, transportation, energy, and public resources outside the infill areas. In response, the Governor's Office of Planning and Research updated its *Environmental Goals and Policy Report* to make it consistent with the planning priorities in Assembly Bill 857. This document is to be the basis for judgments about the design, location, and priority of major public programs, capital projects, and other actions, including the allocation of state resources through the budget and appropriation process. All state departments and agencies must comply.

Some local communities have begun to consider energy issues in land use and have included energy considerations in their general plans. The cities of Chula Vista, Pasadena, Pleasanton, and Santa Monica; the counties and cities of San Francisco and San Luis Obispo; the County of Humboldt; and the San Diego Association of Governments and Southern California Association of Governments are some of the local governments that have taken significant action in furthering smart growth.

Land use practices have been identified as a significant element of the state's plan to achieve the goals of Assembly Bill 32. Some California cities have signed the U.S. Mayors Climate Protection Agreement, committing their cities to aggressive emission reduction targets.

## *Further Action Is Needed to Integrate Land Use Planning and Energy*

In spite of all of the state and local government and non-governmental efforts, much more can and should be done to couple land use and energy. The following recommendations focus on the central role smart growth can play in meeting many of the state's energy goals. Supporting local government as the pivotal players in land use planning, giving local governments responsibility to develop their own greenhouse gas emission reduction plans, involving utilities, expanding the repertoire of smart growth tools available to local governments, and pursuing further research are actions that the state and its partners must take if California is to realize the benefits of integrating land use and energy.

### Require Local Governments to Adopt Greenhouse Gas Emission Reduction Plans

Local government action is key to achieving the state's energy policy goals and the aggressive greenhouse gas emission reductions contained in the Climate Action Team report.

- The state's Assembly Bill 32 plan should require local governments to develop greenhouse gas reduction plans and finance such efforts through the Assembly Bill 32 administrative fee at a level commensurate with the greenhouse gas savings expected from improved land use planning.

### Promote and Facilitate Efficient Land Use Practices That Save Energy and Reduce Greenhouse Gas Emissions

Helping local governments develop and implement energy efficient land use practices and greenhouse gas reduction plans will require input from many sources, including local, regional, and state agencies; developers; utilities; homebuyers; lenders; community groups; non-profit organizations; and other interested stakeholders.

- The Energy Commission should invite stakeholders to participate in an ongoing land use/energy working group that would convene on a regular basis to guide the state's land use and energy research and program development.

Many of California's communities are beginning to address energy use in their land use planning but need help in understanding the options available to them, the available tools they can use, and the benefits that would accrue to both local government and the public.

- Working with their partners, the Energy Commission should establish a central repository for efficient land use information resources. The Energy Commission should produce case studies and best practices guides that describe the successes of local government land use efforts that reduce energy needs and greenhouse gas emissions.

The general plan is the single most important planning document in a community. As a statement of development policies for a locality, the general plan sets forth objectives, principles, standards, and proposals.

- The Legislature should pass legislation that would require local governments to include an energy element in their general plans.

Utilities should play a more influential role in the state's movement toward better land use practices.

- The Public Utilities Commission should require investor-owned utilities to partner with local governments to incentivize energy efficient smart growth in their service territories. The Public Utilities Commission should allow investor-owned utilities to recover the cost of the partnerships.
- Under the authority granted to it by Assembly Bill 2021 (Levine), Chapter 734, Statutes of 2006, the Energy Commission should assist municipal utilities in partnering with local governments to incentivize smart growth in their service territories.

Growth, development and planning are multi-disciplinary activities that involve a wide variety of state agencies and authorities. A state agency working group for efficient land use would enable the state to direct its resources and activities in a coordinated manner.

- The state should form a state agency working group to develop and implement an Efficient Land Use Action Plan for the state. The working group should include, but not be limited to, the Energy Commission, the Governor's Office of Planning and Research, the California Department of Housing and Community Development, the California Air Resources Board and the California Department of Transportation.

### Provide New Tools and Conduct Research to Assist Local Government's Energy and Greenhouse Gas Reduction Planning Efforts

Over the next several years, the Energy Commission will fund research projects that bolster local and regional governmental energy and greenhouse gas emission reduction planning efforts. Direction for research and tool development will come, in part, from the stakeholder group described above and should provide the scientific and technological background to inform sound decision and policy making in California.

- The Energy Commission should complete the update of the Internet-based version of the Planning for Community Energy, Economic, Environmental Sustainability energy module and then continue to provide research and analytical tool development that will allow the state and its partners the ability to:

- Better understand the relationships, processes, and outcomes that underlie smart growth and energy.
- Identify, quantify, evaluate, and verify sustainable energy planning practices and designs.
- Understand the associated complex energy relationships, interdependencies, efficiency, and environmental enhancement opportunities of these practices and designs.
- Develop tools and methods to identify and set energy sustainability goals, as well as to verify that these goals are met.
- Take a comprehensive approach, using life cycle studies or system analyses, to identify the costs, benefits, and trade offs of achieving these goals and to allow for more informed decision and policy making.

### Analyze the Role of the State's Infrastructure Planning and Financing Activities in Promoting Smart Growth

Additional analytical research is necessary for the state to examine its own appropriate role in encouraging efficient land use practices. The Energy Commission expects to examine this in the *2007 Integrated Energy Policy Report*.

The state took a major step toward smart growth with the passage of Assembly Bill 857. This legislation established planning and development priorities for the state's infrastructure development and financing.

- The state should assess compliance with Assembly Bill 857 and provide an assessment of successes and barriers to action.

With the passage of Propositions 1B—E and 84 (*Highway Safety, Traffic Reduction, Air Quality, and Port Security; Housing and Emergency Shelter Trust Fund Act of 2006; Kindergarten-University Public Education Facilities; Disaster Preparedness and Flood Prevention;* and *Supply. Flood Control. Natural Resource Protection. Park Improvements. Bonds. Initiative Statute,* respectively), the state will be able to make a significant impact in addressing deficiencies in and planning for the future of California's transportation, education, shelter, flood and "green" infrastructure.

The investment of the public's funds must support land use that avoids or mitigates increased energy usage and greenhouse gas emissions. Other states, such as Maryland and New Jersey, have implemented programs that direct state infrastructure funds toward projects that incorporate good land use practices and withhold it from projects that do not. The Energy Commission believes that California should explore adopting a similar program.

- The state should develop criteria for smart growth development and prioritize infrastructure funding toward development that meets the criteria.

# CHAPTER 1: INTRODUCTION

## Developing the 2006 Integrated Energy Policy Report Update

In the *2005 Integrated Energy Policy Report*, adopted on November 12, 2005, the California Energy Commission (Energy Commission) noted that "despite improvements in power plant licensing, enormously successful energy efficiency programs, and continued technological advances, development of new energy supplies is not keeping pace with the state's increasing demand." The Energy Commission recommended policies and actions to reduce energy demand further, develop a broader range of alternative energy resources, and improve the state's infrastructure.

On May 1, 2006, the Integrated Energy Policy Report Committee (Committee) noticed a hearing to receive comments on a proposed scope for the 2007 Integrated Energy Policy Report proceeding.[1] The proposed scope built on the comprehensive analysis of issues and the recommendations contained in the *2005 Integrated Energy Policy Report*. The notice provided a preliminary list of key issues for the *2007 Integrated Energy Policy Report* and included proposed activities for the short-term and long-term components of the Integrated Energy Policy Report process.

Parties provided the Committee with comments on the proposed scope at the May 12, 2006, public hearing, as well as in writing in accordance with the direction provided in the notice. Parties and stakeholders provided thoughtful input that the Committee considered in revising the scope of the 2007 Integrated Energy Policy Report proceeding.

The purpose of the *2006 Integrated Energy Policy Report Update,* as required by Senate Bill 1389 (Bowen and Sher), Chapter 568, Statutes of 2002,[2] is to report on the status of selected elements recommended in the *2005 Integrated Energy Policy Report* and, as appropriate, to introduce topics that deserve more attention because of their potential to help the state address key energy goals. As an interim part of the 2007 Integrated Energy Policy Report proceeding, the *2006 Integrated Energy Policy Report Update* provides a

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[1] California Energy Commission 2007 Integrated Energy Policy Report Committee Scoping Order, as part of the 2007 Integrated Energy Policy Report proceeding, Docket #06-IEP-1. August 1, 2006.

[2] Senate Bill 1839 (Bowen and Sher), Chapter 568, Statutes of 2002, requires the California 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 shall use 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" (Pub. Resources Code §25301[a]). Every odd-numbered year, the Energy Commission adopts the *Integrated Energy Policy Report,* which relays the assessments and forecasts to the Governor, the Legislature, and the California public. Every even-numbered year, the Energy Commission prepares an energy policy review to update analysis from the previous Integrated Energy Policy Report or to raise energy issues that have emerged since the previous proceeding (Pub. Resources Code §25302[d]). The *2006 Integrated Energy Policy Report Update* fulfills that requirement for 2006.

continuum of the Integrated Energy Policy Report process by assessing progress made to date on critical elements of the scoping order for the 2007 Integrated Energy Policy Report proceeding.

The *2006 Integrated Energy Policy Report Update* focuses on two topics: (2) the status of progress to meet Renewable Portfolio Standard (RPS) goals to generate 20 percent of the state's electricity from renewable resources by 2010 and 33 percent by 2020; and (2) an investigation of energy saving opportunities related to sustainable land use planning, and "smart growth" principles.

The Committee held a public workshop on December 7, 2006, to discuss the recommendations contained in this report. After reviewing oral and written comments presented at that workshop, the Committee prepared this final report, which will be considered for adoption by the Energy Commission on January 3, 2007. Once adopted, the final report will be transmitted to the Governor and Legislature.

## Renewable Portfolio Standard

The *2005 Integrated Energy Policy Report* concluded that statewide renewable procurement is not occurring at a pace that will reach RPS goals by 2010 and, as a result, the RPS process is in need of midcourse review and correction. The *2006 Integrated Energy Policy Report Update* considers the issues associated with slow progress on the RPS and makes recommendations for improvements to help meet the short- and long-term RPS goals. The Committee held two well-attended workshops to explore specific RPS topics, one on July 6, 2006 and one on August 22, 2006.

## Investigating the Land Use / Energy Connection

Because land use decisions have a significant impact on energy use and infrastructure, the Committee recommended that an examination of existing studies and policies related to sustainable land use planning and energy saving opportunities be conducted as part of the *2006 Integrated Energy Policy Report Update*. The Energy Commission is collaborating in this effort with the Governor's Office of Planning and Research, as well as other state and local agencies. A public workshop on September 22, 2006, launched the investigation and included 14 speakers and significant public participation. Staff has developed a number of recommendations to develop the land use planning/energy relationship and take advantage of its significant potential to help meet the state's energy and greenhouse gas reduction goals.

## Organization of the Report

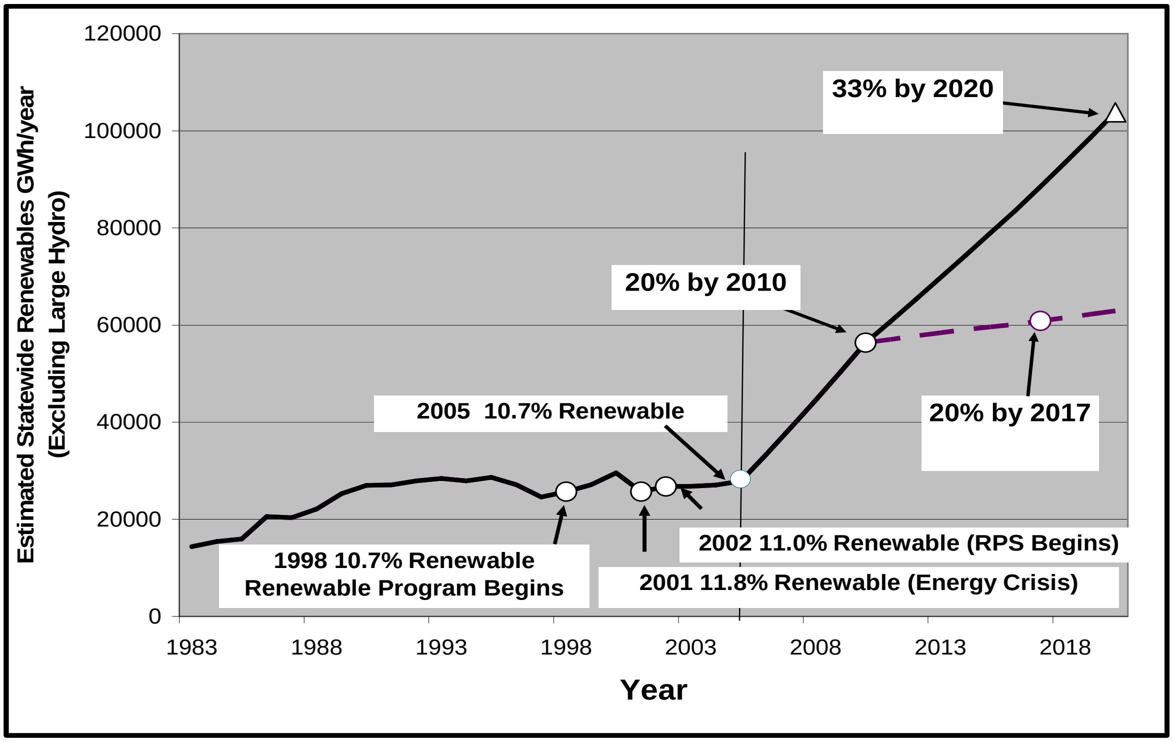
The *2006 Integrated Energy Policy Report Update* devotes one chapter to each topic and explores each in depth. Both chapters provide a historical perspective, a review of current status, and a discussion of barriers that jeopardize progress. They also make recommendations for their respective topics: to further progress in meeting RPS goals and to facilitate the integration of land use planning and energy considerations using smart growth principles to help the state meet energy and greenhouse gas reduction goals.

# CHAPTER 2: MIDCOURSE REVIEW OF THE RENEWABLE PORTFOLIO STANDARD

## Introduction

As shown in Figure 1, halfway between the 2002 legislative enactment and the 2010 target date, California has made little progress toward increasing the percentage of renewable energy in the system mix since the Renewable Portfolio Standard (RPS) program was created. In fact, compared to 2002—the year before the RPS took effect—renewable generation as a percentage of total statewide generation decreased by 0.3 percent in 2005.

**Figure 1. California's Renewable Energy Goals**




Source: California Energy Commission.[3]

In 2002, California established its RPS program with the goal of increasing the amount of renewable energy in the state's electricity mix. The law requires retail sellers, defined as

[3] California Energy Commission, Gross System Power 1998-2005, http://energy.ca.gov/electricity/gross_system_power.html. Gross System Power renewable percentages are based on total reported generation and allow for consistent comparison of renewable generation across multiple years. Renewable Portfolio Standard targets are defined as renewable generation as a percentage of retail sales. In 2005, renewable generation in California represented approximately 11.9 percent of retail sales.

investor-owned utilities (IOUs), community choice aggregators, and energy service providers (ESPs), to increase the portion of electricity from retail sales by at least 1 percent per year toward a goal of 20 percent. Initially, that target was to be reached by 2017, but the state has accelerated timing of the 20 percent goal to 2010.

Under the law, publicly owned utilities (POUs)—while not defined as retail sellers and therefore not subject to the 20 percent by 2010 goal—are nonetheless responsible for implementing a renewable portfolio standard that recognizes the Legislature's intent to encourage renewable resources.[4] The law does state explicitly, however, that the RPS program is intended to attain a target of 20 percent renewables for the state as a whole because of the statewide benefits of using renewable energy:

> Increasing California's reliance on renewable energy resources may promote stable electricity prices, protect public health, improve environmental quality, stimulate sustainable economic development, create new employment opportunities, and reduce reliance on imported fuels.....The development of renewable energy resources may ameliorate air quality problems throughout the state and improve public health by reducing the burning of fossil fuels and the associated environmental impacts.[5]

More recently, the Legislature reaffirmed its commitment to renewables as a mitigation strategy for the effects of greenhouse gas emissions. Assembly Bill 32 (Nuñez), Chapter 488, Statutes of 2006, states that California has long been a national and international leader in its environmental stewardship efforts, including renewable energy standards, and will continue this tradition of environmental leadership by placing California at the forefront of efforts to reduce greenhouse gas emissions.

Although IOUs have signed contracts for as much as 3,936 megawatts (MW) of renewable capacity, only 242 new MW are actually on line and delivering energy. Because the RPS statute includes provisions for flexible compliance—with retail sellers given up to three years to make up deficits in current year RPS targets—the IOUs have argued that they have until 2013 to meet the 20 percent by 2010 goal.

Recently enacted Senate Bill 107 (Simitian and Perata), Chapter 464, Statutes of 2006, which addresses flexible compliance among other RPS issues, has yet to be fully considered by the California Public Utilities Commission (CPUC).[6] However, in October 2006, the CPUC adopted Decision 06-10-050 which states, "Nothing presented here convinces us now to alter the clearly stated requirement of 20% by 2010. To the contrary, we maintain that the reportable target by 2010 is 20% of retail sales. The reportable result

[4] Senate Bill 1078 (Sher), Chapter 516, Statutes of 2002.
[5] Ibid.
[6] Senate Bill 107 states: "The flexible rules for compliance shall apply to all years, including years before and after a retail seller procures at least 20 percent of total retail sales of electricity from eligible renewable resources."

is actual deliveries."[7] The Energy Commission concurs with the CPUC's opinion and reaffirms that the 20 percent goal requires renewable electricity that is delivered, not merely contracted for.

To meet the 20 percent by 2010 RPS goal, several barriers must be removed. These include:

- Insufficient transmission upgrades and additions to access remote renewable resources.
- Uncertainty regarding the financeability of supplemental energy payments (SEPs).
- Complexity and lack of transparency in the bidding, ranking, and contracting processes used to select renewable projects and to develop the market price referent (MPR) and benchmark time of delivery (TOD) factors.
- Inadequate consideration of contract failure and project delays that jeopardize attainment of the 2010 RPS goals.
- Inattention to near-term opportunities to repower old and out-of-date wind turbines at sites where infrastructure already exists.

## Process Used to Develop Midcourse Review

On July 6, 2006, the Integrated Energy Policy Report Committee (Committee) and CPUC Commissioner John Bohn held a workshop on the RPS midcourse review. Topics for the workshop included exploring both regulatory and statutory solutions to meet California's renewable energy goals, including: increasing transparency; ensuring that renewable procurement occurs quickly and efficiently; addressing transmission and integration issues; applying RPS targets consistently to all load-serving entities; streamlining accounting for RPS compliance; and addressing jurisdictional issues and financing.

On August 22, 2006, the Committee and CPUC Commissioner Bohn held a second workshop on the RPS midcourse review, focusing on a smaller number of topics in greater depth. Specifically, the workshop scope invited participants to discuss the following topics:

- Given the magnitude of uncertainty in natural gas price forecasts, can the market price referent / time of delivery methodology be simplified and more transparent, consistent with similar market estimates used for energy efficiency and for non-renewable procurement processes?

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[7] California Public Utilities Commission, *Opinion on Reporting and Compliance Methodology for Renewable Portfolio Standard Program,* D.06-10-050, October 19, 2006.

- Reflecting the investor-owned utilities' high level of commitment to achieve 20 percent by 2010, efforts to keep contract failure to a minimum, and the inherent uncertainties of new power plant development, how can the investor-owned utilities, developers, and others make sure milestones are met and contracts result in on-line power plants?
- Given the predominant support at the July 6, 2006, workshop to retain the structure of the RPS solicitations through 2010, can the bilateral contracting process be streamlined to ramp up the pace of renewables development consistent with the longer term goal of 33 percent by 2020?
- In support of the 33 percent by 2020 goal, how can the transmission ranking cost reports used in evaluating bids in competitive RPS solicitations, the California Independent System Operator (California ISO) interconnection queue, and California ISO cost allocation process be revised to encourage the most cost effective timing and scale for infrastructure and project development in areas known to have large-scale potential for renewable energy?

# Status of RPS Compliance

Nearly four years after the RPS program went into effect, California has made very little progress in bringing new renewable projects on line. Statewide, renewable energy as a percentage of retail sales increased less than 0.6 percent from 2002 to 2005. Individual progress made by IOUs, POUs, and ESPs is discussed in more detail below.

## *Progress Made by Investor-owned Utilities*

Table 1 shows the three major IOUs' renewable energy procurement in 2002 (the year before the RPS began) and 2005 (latest available annual data) and compares RPS procurement during the period between the two years as a percent of sales.[8]

As shown in the table, San Diego Gas and Electric (SDG&E) has made the most progress in increasing its renewable purchases—moving from 1 percent in 2002 to 5.2 percent in 2005—but still has far to go to meet the 20 percent goal by 2010. Similarly, by the end of 2005, Pacific Gas and Electric (PG&E) had only increased its renewable generation by 1.5 percent compared to 2002 levels and will need an additional 8.1 percent to meet its 2010 goal. Southern California Edison (SCE), although furthest along in meeting the 2010 goal, has only increased its renewable generation by 0.2 percent between 2002 and 2005, making little progress in the last three years despite the proximity of the Tehachapi

[8] For 2002, total retail sales and renewable procurement were reported in the "*Report to the California Public Utilities Commission: Utility Procurement of Renewable Energy-2001 and 2002*", filed by each investor-owned utility under Rulemaking 01-10-024. For 2005, total retail sales and renewable procurement were reported in the investor-owned utilities' August 1, 2006 Renewable Portfolio Standard compliance filings, under Rulemaking 06-05-027.

Wind Resource Area and various mechanisms that allow SCE to develop the needed transmission.

**Table 1. Comparison of Renewable Generation, 2002–2005**

| | PG&E | SCE | SDG&E | Total |
|---|---|---|---|---|
| 2002 Retail Sales (GWh) | 70,797 | 68,462 | 14,301 | 153,560 |
| 2002 Generated/Sold RPS Renewable (GWh) | 7,392 | 11,658 | 141 | 19,191 |
| BASELINE: 2002 IOU RPS Renewable Generation as % of IOU Retail Sales | 10.4% | 17.0% | 1.0% | 12.5% |
| 2005 Retail Sales (GWh) | 72,727 | 75,302 | 16,002 | 164,030 |
| 2005 RPS Renewable Generation (GWh) | 8,650 | 12,930 | 825 | 22,405 |
| IOU RPS Renewable GWh as % of IOU Retail Sales | 11.9% | 17.2% | 5.2% | 13.6% |

Sources: 2002 data from 2004 Annual Procurement Target filings of PG&E, SCE, and SDG&E to the CPUC, as required in Rulemaking 01-10-024; 2005 data from August 1, 2006 Renewables Portfolio Standard Compliance Filing to CPUC of PG&E, SCE, and SDG&E.

SCE's lackluster performance may suggest revisiting the recommendation in the *2004 Integrated Energy Policy Report Update* of higher targets for the IOU with the service territory most richly endowed with renewable resources.

The IOUs have made more progress in contracting for future deliveries than in increasing delivered renewable electricity. Since California's RPS was established in 2002, the IOUs have conducted two cycles of renewable energy solicitations and negotiated a number of bilateral agreements with developers. As a result the IOUs have signed 69 contracts for between 2,552 and 3,936 MW of new and existing renewable capacity, with the range reflecting potential build-out options. If all of these contracts come to fruition, they will represent significant progress toward meeting the state's RPS goals.

The *Energy Action Plan*, adopted by the CPUC in May 2003, identified 4,200 MW as the amount of incremental renewable capacity needed to meet the 2010 goal.[9] The amount of renewable capacity under contract therefore might appear to represent significant progress. However, contracts for 104-116 MW (depending on build out) have been canceled, at least 10 are not expected to deliver until 2010 or later, and at least 13 have been delayed. In addition, a significant share of the contracted capacity is from

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[9] Consumer Power and Conservation Financing Authority, California Public Utilities Commission, and California Energy Commission, *Energy Action Plan*, May 8, 2003, page 6, http://www.cpuc.ca.gov/PUBLISHED/REPORT/28715.htm.

renegotiated contracts with facilities developed prior to the RPS and does not represent new development. More importantly, to date only 242 MW of new facilities under contract are currently on line and delivering electricity.[10] By comparison, since 2002 more than 1,500 MW of new wind capacity has been installed in Texas, which recently surpassed California as the largest market for wind power in the United States.

The amount of new energy expected from contracts that have been signed as of October, 2006, is between 7,015 gigawatt hours (GWh) and 11,786 GWh per year (less transmission and distribution losses).[11] The larger figure is the maximum estimated available generation if all contractual options to increase capacity are exercised, which is by no means certain. However, only an estimated 785 GWh per year will be produced from facilities that are on line at the end of October, 2006.[12] To meet the RPS goal of 20 percent by 2010, the IOUs, collectively, will need to add between 1,543 GWh and 6,314 GWh annually over the next three years. Assuming an average 50 percent capacity factor, the additional energy needs translate to between 352 MW and 1,442 MW of additional renewable generating capacity by 2010.[13]

## Investor-Owned Utilities' Expectations of RPS Progress

The IOUs continue to affirm their commitment to the RPS and in public comments remain committed and optimistic about meeting their targets. In July 2004, PG&E spokeswoman Darlene Chiu told the *San Francisco Chronicle*, "We think we're on our way to hitting the target," and insists that PG&E will "meet its mark."[14] Similarly, in July 2004, PG&E spokesperson Cynthia Pollard told *The Bakersfield Californian* that "the utility is on target to meet the 2017 deadline and if the deadline is moved up to 2010, that won't be a problem."[15] This position was reinforced in a July 2005, workshop on the *2005 Integrated Energy Policy Report*, at which PG&E stated, "PG&E intends to meet the RPS goal by the year 2010… We are currently at 13 percent, and if we continue to add at least 1 percent a year, we will meet our legislative mandate by the year 2010."[16] Recently, PG&E advertisements have focused on the company's commitment to renewable power and touted the utility as supplying 30 percent of its customer load from renewable resources.

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[10] See http://www.energy.ca.gov/portfolio/contracts_database.html, updated October 5, 2006.

[11] Ibid. Current and future deliveries in most cases are estimated from project capacities and typical capacity factors; actual contracted deliveries have been redacted from publicly available documents for many projects.

[12] Ibid. This amount includes additional energy from repowered wind facilities.

[13] Based on California Energy Commission estimates of 2010 retail sales of 35,360 gigawatt hours, less 2005 RPS-eligible generation of 22,405 gigawatt hours, less expected generation from contracts signed as of October 2006 but not on line in 2005 (6,641 to 11,412 GWhs), and assuming a 50 percent average capacity factor for the 2010 renewable resource mix.

[14] *San Francisco Chronicle*, September 24, 2006, page 1, article by Marc Misener.

[15] *The Bakersfield Californian*, July 13, 2004, "Utilities on Board with Renewables."

[16] Testimony of Les Guliasi, Pacific Gas & Electric Company, transcript of Integrated Energy Policy Report Workshop on California New Electricity Resource Loading Order, July 25, 2005, pp. 128-133.

SCE has also expressed confidence in its ability to meet the RPS targets. In September 2003, SCE announced that "a record 23.4 percent" of its June 2003 power supply came from renewable resources.[17] In April 2005, SCE stated, "We are on track to reach California's renewable power standard of 20% for utilities well ahead of schedule."[18] However, by August 2005, SCE had somewhat tempered its claims in the press, stating only, "The utility intends to increase its renewable energy share to 20 percent by 2010, as requested by the state's power planning agencies."[19]

At the July 6, 2006, Integrated Energy Policy Report workshop, SCE vice president Pedro Pizarro stated, "It's important that the market as a whole understand the depth of our commitment to the renewables program," and that SCE is "willing to roll up our sleeves and work with them [CPUC] and with you [Energy Commission], absolutely."[20] However, an article in the *San Gabriel Valley Tribune* quoted SCE Director of Renewable and Alternative Power Stuart Hemphill as saying, "The state's goal is to have 20 percent of customers' energy needs met by renewable power by 2010. But that's going to be difficult to meet – not just for Edison, but for everyone."[21]

Historically, SDG&E has also committed to the state's RPS goals. An October 2004, article in *The San Diego Union-Tribune* states, "SDG&E last year expected it would reach a 7 percent renewable level by now but the failure of some wind-power contractors to fulfill commitments left the utility short of that target. [SDG&E spokesman Ed] Van Herik says the company is still on track to reach the 20 percent goal by 2010."[22]

In addition, at the July 6, 2006, Integrated Energy Policy Report workshop, SDG&E's Terry Farrelly reported that, "We fully expect that we will be at 20 percent in 2010. And we have projects under contract that are at 13 percent right now for the year 2010."[23] Further, SDG&E's written comments indicate their intent to exceed the 20 percent goal: "The company intends to issue additional RFOs in order to continue our purchasing strategy under which we intend to bring the portion of our energy that comes from renewables beyond 20% by 2010."[24]

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[17] "Edison Takes Lead in Using Renewable Energy Resources," *San Gabriel Valley Tribune*, September 20, 2003.

[18] "SCE to Solicit More Renewable Power," April 15, 2005, http://www.edison.com/pressroom/pr.asp?bu=&year=0&id=5486, accessed November 1, 2006.

[19] "Giant Solar Plant Planned," *Riverside Press-Enterprise*, August 10, 2005.

[20] Testimony of Pedro Pizarro, Southern California Edison, transcript of the Energy Commission's Integrated Energy Policy Report Committee workshop, Midcourse Review of the Renewables Portfolio Standard Process, July 6, 2006.

[21] "Edison Expands in Green Energy," *San Gabriel Valley Tribune*, July 14, 2006.

[22] "Power Content Label on SDG&E Bill is Called Misleading," *The San Diego Union-Tribune*, October 30, 2004.

[23] Testimony of Terry Farrelly, San Diego Gas & Electric, transcript of the July 6, 2006 Integrated Energy Policy Report Committee workshop, Midcourse Review of the Renewables Portfolio Standard Process.

[24] San Diego Gas and Electric Company, Comments. July 6, 2006 Integrated Energy Policy Report Committee workshop, Midcourse Review of the Renewables Portfolio Standard Process.

However, according to a June 18, 2006, article in *The San Diego Union-Tribune*, "[Sempra Chief Executive Officer Donald] Felsinger says he's reluctant to invest in renewable energy technologies beyond what the state requires. 'I will deploy our dollars in a way that is less controversial,' Felsinger said."[25] This position is difficult to reconcile with SDG&E's comments indicating its intent to exceed the 20 percent goal.

Other IOU comments at the July 6, and August 22, 2006, Integrated Energy Policy Report workshops indicate some equivocation on the goals, with expectations that the 2010 goal is jeopardized by barriers such as timely transmission development and difficulty in financing projects. Despite its stated commitment to the RPS goals, SCE articulated concerns about penalties, saying: "And so we want the ability to demonstrate to the PUC that we made our best efforts to meet those targets. And to the extent that in spite of our best efforts, situations have occurred that prevent us from actually having sufficient electrons spinning the meter by 2010. ….we want the chance to be able to demonstrate to the PUC how our efforts were there and why it happened, and why there might be a good case for excusing us from any specific penalties."[26]

SDG&E considers the main impediments to meeting RPS goals as: "the current lack of adequate transmission infrastructure [which] significantly diminishes the utilities' ability to access renewable generation," and the "difficulty and delay in obtaining SEP funds intended to spur development of new renewable resources could undermine the success of the RPS program." According to SDG&E, "slow or uncertain regulatory action is the de facto equivalent of killing a project, and the uncertainty that it adds to the industry increases overall costs and decreases the viability of future projects. Of equal concern is the regulatory burden associated with requests for SEP funds."[27]

## Progress Made by Publicly Owned Utilities

POUs provide 25–30 percent of the retail electricity sold in California, making their participation in the RPS essential to meeting statewide renewable goals. Based on reported 2005 deliveries, total POU renewable generation amounts to 8.2 percent of their total reported generation, representing an increase of approximately 0.7 percent compared to 2003 levels. To meet the 20 percent goal, POUs as a group must therefore increase renewable generation by 11.8 percent above their 2005 deliveries.[28]

The RPS legislation initially made each POU responsible for "implementing and enforcing a renewable portfolio standard that recognizes the intent of the Legislature to

[25] "Sempra Generating New Energy," *The San Diego Union-Tribune*, June 18, 2006.
[26] Pedro Pizarro, transcript of the July 6, 2006 Integrated Energy Policy Report Committee workshop, Midcourse Review of the Renewables Portfolio Standard Process.
[27] Terry Farrelly, San Diego Gas & Electric, transcript of the July 6, 2006 Integrated Energy Policy Report Committee workshop, Midcourse Review of the Renewables Portfolio Standard Process.
[28] California Energy Commission, data reported in *Annual Report to the California Energy Commission: Power Source Disclosure Program*, March 2006, pursuant to Senate Bill 1305 (Sher), Chapter 796, Statutes of 1997.

encourage renewable resources, while taking into consideration the effect of the standard on rates, reliability, and financial resources and the goal of environmental improvement."[29] However, POUs are not bound to the initial goal established for IOUs, ESPs, and community choice aggregators and are in fact authorized to set their own target percentages and years.

Twenty-nine of 36 POUs—representing approximately 98 percent of total POU load in the state—have established some type of RPS commitments. At least 16 of these POUs have taken measurable steps to acquire renewable resources, with several at 30 percent and at least one at 100 percent.

The RPS policies established by POUs vary considerably. Some are more and others less stringent than the policies established by Senate Bill 1078 (Sher), Chapter 516, Statutes of 2002 for the state's IOUs, ESPs, and community choice aggregators. For example, targets set by POUs range from 5 to 40 percent, with target dates from 2007 to 2017.

The cities of Santa Clara, Roseville, Redding, and a handful of other smaller POUs have set high targets, ranging from 46–100 percent renewable generation. Most of the larger POUs—those with more than 1,000 GWh annual sales—have a target of 20 percent by 2017,[30] with the notable exceptions of the Sacramento Municipal Utility District (SMUD) and the Los Angeles Department of Water and Power (LADWP). The SMUD target is 12 percent by 2006 and 23 percent by 2011,[31] while LADWP has committed to reaching 20 percent by 2010 and is aggressively pursuing that goal.[32]

For 2005, LADWP and SMUD reported 5 and 13 percent renewable generation, respectively. LADWP's reporting, however, includes approximately 2.7 percent from hydropower facilities above 30 MW. Although many of the POUs consider hydroelectric projects larger than 30 MW as part of their renewable portfolio, the RPS program for IOUs does not consider these facilities as eligible renewable resources. The *2005 Integrated Energy Policy Report* recommended applying RPS rules consistently to all entities, including POUs. Toward this end, the recently passed SB 107 clarifies that renewable energy claimed by POUs for RPS compliance must meet the same eligibility requirements as those applied to the IOUs.[33]

With the passage of SB 107, generation from hydroelectric projects larger than 30 MW cannot be reported by POUs as eligible renewable energy. This change will make it more

[29] Senate Bill 1078, (Sher), Chapter 516, Statutes of 2002.

[30] KEMA, *Publicly Owned Electric Utilities and the California RPS: A Summary of Data Collection Activities*, November 2005, CEC-300-2005-023.

[31] Sacramento Municipal Utility District press release, "SMUD Seeks Renewable Power Offers," August 2006, http://www.smud.org/news/releases/06archive/08_25_Renewable_offers.pdf.

[32] American Public Power Association, "10 Questions with Los Angeles Department of Water and Power," http://www.appanet.org/utility/index.cfm?ItemNumber=17591&sn.ItemNumber=14183.

[33] Senate Bill 107 (Simitian and Perata), Chapter 464, Statutes of 2006.

difficult for LADWP—and other POUs like the Imperial Irrigation District (IID) that purchase generation from large hydroelectric projects—to achieve 20 percent RPS-eligible renewables by 2010.

In 2005, the state's three largest POUs—LADWP, SMUD, and IID—accounted for 60 percent of the POU load and 14.4 percent of the total state electric load. Considering only eligible renewable generation, between 2003 and 2005 SMUD increased renewables from 9 to 11 percent, and LADWP increased from 1.8 to 2.4 percent, while IID decreased renewables from 12.0 to 7.6 percent.[34]

POUs continue to make progress. They have contracted for potential deliveries of more than 4,700 GWh, equivalent to 8.2 percent of 2003 POU load. There were nine POU renewable energy solicitations between January 2002 and December 2005. Since then, contracting activity has expanded and intensified. LADWP recently announced a contract with PPM Energy for 82 MW of wind power from Wyoming, while SiliconValley Power announced the purchase of 105 MW of wind power from a new wind project in Washington.[35] In addition, Turlock Irrigation District, the Northern California Power Agency, and the South California Public Power Authority have all recently issued requests for proposals for renewable energy supplies.

However, to meet their share of the state's goal, POUs will need to increase RPS-eligible renewable generation by more than 2 percent each year between 2006 and 2010. One action that could help achieve these aggressive increases is the effort to access renewable resources in the Imperial Valley. Both LADWP and IID are involved in the Green Path transmission planning process that promises to open access to geothermal, wind, and solar resources in Imperial Valley. This process is described more fully later in the report in the section on renewable transmission obstacles.

Because of differences in percentage targets, geographical eligibility rules, timeframes, and the level of enforcement, it is difficult to determine POU progress compared to that of the IOUs. One approach is to compare the difference between the POUs qualifying renewable purchases and their ultimate RPS targets to derive the incremental amount required to achieve their internal goals. The same percentages can be derived for the state's IOUs, based on a 20-percent-by-2010 target.

As of 2003, the last year for which data are available, POUs' incremental renewable energy needs to meet their own internal targets represented 12.5 percent of their load. The comparable figure for the IOUs is 6.1 percent. By this measure, the POU targets are more aggressive than those of the IOUs, in part because POUs are starting with smaller

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[34] California Energy Commission, data reported in *Annual Report to the California Energy Commission: Power Source Disclosure Program,* March 2006, pursuant to Senate Bill 1305 (Sher), Chapter 796, Statutes of 1997..

[35] KEMA, *Summary of the California Energy Commission's Renewables Portfolio Standard Contractor Reports, and the Status of Renewables Portfolio Standard Contracting and Regulation*, June 2006, CEC-300-2006-012.

percentages of renewable power and in part because several POUs have set more aggressive goals than those of the IOUs.

## Publicly Owned Utilities' Goals for Greenhouse Gas Reduction

In the first half of 2006, the California Municipal Utilities Association (CMUA) developed *California's Publicly Owned Electric Utilities' Principles Addressing Greenhouse Gas Reduction Goals*, which endorses the following principles, immediate actions, and long-term actions. These principles underscore the importance of renewable energy as a greenhouse gas mitigation strategy and will be important in encouraging POUs to increase the amount of renewable energy in their electricity portfolios.

The local governing boards of many POUs have adopted these principles, including Alameda Power and Telecom, Azusa Light & Water Department, Biggs Electric Utility, Burbank Water & Power, City of Gridley, City of Healdsburg, Lompoc Utility Department, LADWP, Modesto Irrigation District, Northern California Power Agency, City of Palo Alto, Port of Oakland, Roseville Electric Department, SMUD, City of Shasta Lake, City of Santa Clara, and Trinity Public Utilities District:[36]

- Each utility will develop a greenhouse gases reduction plan, consistent with the state's reduction goals, adopted by its elected governing board in public hearings, and provided to the California Energy Commission when adopted and whenever updated. Smaller utilities may choose to aggregate their plans into a single, larger plan. Each utility will explore the impact of a "sustainable portfolio" to allow the utility to meet its overall load-based greenhouse gas reduction goals by balancing investments in renewable energy, energy efficiency and demand reduction, carbon trading, carbon emissions mitigation, and/or through other innovative ways. In the design of programs to reduce greenhouse gases emissions, each utility supports the concept of receiving credit for early action to reduce greenhouse gases emissions.
- As a means of meeting greenhouse gases reduction goals, each utility will proactively implement state law, which requires that "…each local publicly owned electric utility, in procuring energy, shall first acquire all available energy efficiency and demand reduction resources that are cost-effective, reliable, and feasible." Such investment in cost-effective energy efficiency and demand reduction resources will not be limited to public benefits funds allocations.
- As a means of meeting greenhouse gases reduction goals and meeting energy needs after implementing the principles above, each utility will first pursue renewable energy supplies, and second, other non greenhouse gas emitting energy resources and clean fossil resources:

[36] California's Publicly Owned Electric Utilities "Principles Addressing Greenhouse Gas Reduction Goals," http://www.smud.org/about/pdf/ghg_cmua.pdf.

a. In considering renewable resources in competition with fossil fuel resources, each utility will quantify the financial risk of greenhouse gas producing resources in their planning and procurement process, including but not limited to a quantified carbon emissions risk adder for both in-state and out-of-state resources.

b. Each utility will continue to aggressively pursue its renewable energy supply in accordance with its renewable portfolio standard (RPS), pursuant to Public Utilities Code section 387.

c. Each utility will facilitate distributed generation/combined heat and power (DG/CHP) projects that reduce greenhouse gases emissions in their service territory by evaluating transmission and distribution benefits and providing equitable methods for the DG/CHP owner to sell excess electricity to the host utility.

d. Each utility will consider environmental justice issues in its overall resource procurement and greenhouse gas reduction policies.

- Each utility will support standardized, mandatory greenhouse gases reporting from all significant sources. Smaller utilities may choose to aggregate their greenhouse gases reporting.
- Each utility will provide measurement and verification of programs that reduce greenhouse gases emissions.
- Each utility will provide education for its customers on ways that they can reduce their greenhouse gases emissions and provide assistance where feasible. Any utility that provides financial assistance shall receive credit for appropriate share of the reductions toward that utility's goals.

### *Progress Made by Energy Service Providers*

ESPs are also required to meet the 20 percent renewable goal by 2010, and the CPUC adopted procedures for their participation in October 2006. The CPUC decision states, "The 20% by 2010 goal is clear; ESPs will either take the appropriate steps to meet the goal, or they will explain to us why their potential penalties for failing to meet the goal should be reduced." To date, however, ESPs as a group only provide about 0.25 percent of their retail sales from renewable sources, indicating that they may be hard pressed to catch up with other load serving entities.[37]

## Barriers to Meeting Renewable Goals

The Integrated Energy Policy Report Committee found five main barriers to achieving the state's 2010 RPS goals. First, transmission access for renewables is not sufficient.

[37] California Public Utilities Commission, Decision 06-10-019 in Rulemaking 06-02-012, October 5, 2006.

Transmission projects that could connect large volumes of renewable resources to the state's electricity grid have been identified, but are suffering continuing delays. These projects are essential to access wind resources in Tehachapi, as well as geothermal and solar resources in Imperial Valley, by 2010. Without adequate transmission access, developers will not be able to take advantage of these promising resources, further jeopardizing the RPS goals.

Second, many stakeholders have raised concerns that SEP awards, under the current program structure, do not represent a financeable revenue stream, making it impossible for projects that require SEPs to receive the financing needed to move forward. Concerns have been raised about the possibility of the state borrowing the funds set aside for SEP awards or allocating these funds for other purposes. In addition, the SEP structure requires separate agreements with RPS project proponents and with the state, on top of project contracts with IOUs.

Third, there is the complexity and lack of transparency in the bidding, ranking, and contracting processes used to select renewable projects. Bidders need better information about how bids will be evaluated to be able to structure their bids to best meet the needs of the IOUs. Policy makers need better assurance that IOU selection criteria and contract pricing are aligned with the state's interests. For those projects that require SEPs, appropriate documentation that objectively demonstrates the need for subsidy is required before public funds can lawfully be awarded. Excessive opaqueness in each of these areas could jeopardize the ability of renewable projects to come on line in time to meet the 2010 RPS goals.

Fourth, the reliance on contracts, rather than energy deliveries, as a measure of progress toward the RPS goals puts achievement of the goals at risk if those contracts are delayed or fail to come to fruition. Many contracts are already experiencing significant delays, and others have been cancelled, underscoring the need for IOUs to account for potential contract failure in their contracting procedures to ensure that the RPS goals are met.

Finally, there has been little progress in repowering of aging wind facilities that are already connected to the grid. Many of these turbines have been in operation since the 1980s and represent older, less efficient technologies. Repowering would result in additional renewable energy delivered to the grid, which would further the state's RPS goals. However, because of the structure of current contracts, as well as provisions in the U.S. Tax Code, these facilities have little economic incentive to repower.

These barriers are discussed in more detail below. Without prompt action to address these problems with the RPS program, the state's ability to meet its RPS goals and secure the benefits of renewable energy for the state—particularly California's greenhouse gas emission reduction goals—continues to be threatened.

## *Transmission as a Barrier to Renewable Energy Development*

The lack of transmission infrastructure to access remote renewable resources is the most critical barrier to meeting California's 20 percent target by 2010. Several key transmission project segments to bring on near-term transmission upgrades for renewable projects have yet to receive permits from the CPUC to move into construction. Despite efforts by utilities and the renewable industry in working groups for the Tehachapi wind area and Imperial Valley geothermal and solar resources areas, California's efforts to spur investments in renewable transmission infrastructure have not yet been successful. Cost allocation issues for renewable transmission also continue to plague renewable transmission projects. Unless these challenges are resolved, renewable transmission projects will continue to languish and thwart California's ability to meet RPS targets.

California's existing RPS compliance framework allows for the implicit use of unbundled renewable energy certificates (RECs), which will help in overcoming some of the transmission barriers to renewable resource development. The CPUC, in D.05-07-039, relaxed the delivery requirements for IOUs such that the renewable energy procured pursuant to RPS need not be delivered into the service territory of the purchasing utility, but must only be delivered into the wider California ISO control area. Despite this relaxation in delivery requirements, unless sufficient transmission infrastructure is developed to connect renewable resources into the California ISO bulk transmission system and to the transmission systems of municipal utilities, these renewable resources will remain inaccessible to the state's electric utilities.[38] It is critical that the state undertake sufficient advance planning and make timely permitting decisions to allow for the efficient development of renewable transmission.

### Status of Permitting Renewable Transmission

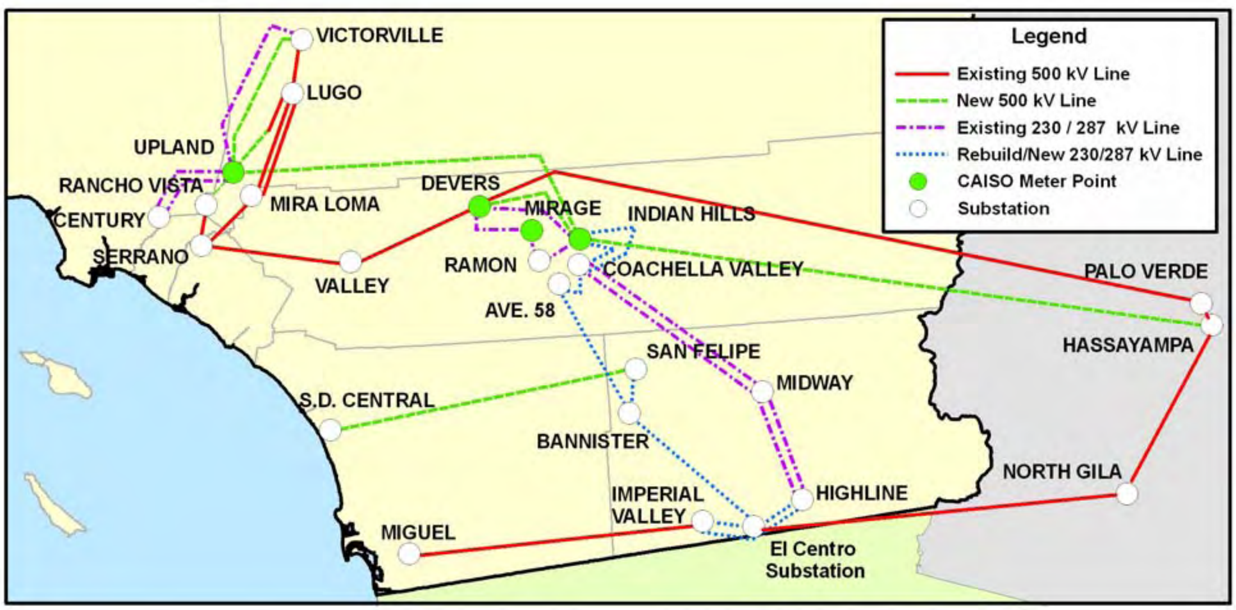
The Energy Commission's *2005 Strategic Transmission Investment Plan* and *2005 Integrated Energy Policy Report* identified three vital transmission projects to interconnect renewable resources that provide significant near-term benefits to California. In evaluating candidate projects for a favorable recommendation, the Energy Commission limited its evaluation to projects that could be on line by 2010 and that were still in need of permitting approval. These projects are the Sunrise Powerlink Project; the Antelope Transmission Project (Phase 1 of the Tehachapi Transmission Plan); and the Imperial Valley Transmission Upgrades. The following discussion provides the status on these projects.

[38] California Public Utilities Commission, staff white paper, *Renewable Energy Certificates and the California Renewable Portfolio Standard Program*, April 20, 1006, p. 6.

### *Sunrise Powerlink Project*

The San Diego Gas & Electric proposed 500-kilovolt (kV) Sunrise Powerlink Project (see Figure 2) would provide significant near-term system reliability benefits to California, reduce system congestion and its resultant costs, and provide an interconnection to both renewable resources located in the Imperial Valley and lower cost out-of-state generation. Without this proposed project, it is unlikely that SDG&E will be able to meet its RPS targets, ensure system reliability, or reduce reliability must-run (RMR) and congestion costs.

**Figure 2. Sunrise Powerlink Project**




Source: California Energy Commission

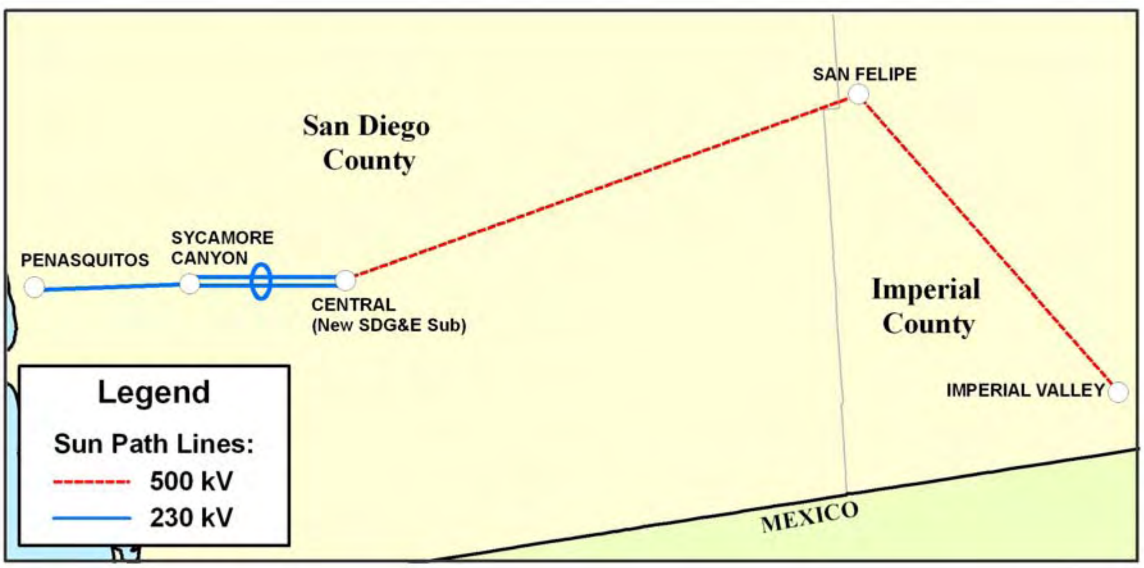
SDG&E filed a partial application (A.05-12-014) for a Certificate of Public Convenience and Necessity (CPCN) with the CPUC on December 14, 2005. The CPUC is the California Environmental Quality Act (CEQA) lead agency, and the Bureau of Land Management (BLM) is the lead agency under the National Environmental Policy Act (NEPA). The filing contained information on the need for the project but did not contain information on a proposed route for the project; hence, it did not include the Proponent's Environmental Assessment. The filing indicated only that the project would consist of a 500-kV line connecting the existing Imperial Valley Substation to a new "Central" substation located somewhere in central San Diego County, along with additional new 230-kV lines west of the new Central substation.

SDG&E entered into a Memorandum of Agreement with the Imperial Irrigation District (IID) and Citizens Energy Corporation on March 16, 2006, to form a partnership for building a portion of the Sunrise project. The Memorandum of Agreement calls for

IID/Citizens Energy to build a new 500-kV line from the existing SDG&E/IID Imperial Valley Substation to a new IID San Felipe Substation, then to the existing SDG&E Narrows Substation (this project is known as the Green Path Project- Southwest). SDG&E would then be responsible for building the 500-kV portion from the Narrows Substation to the new Central Substation, plus the planned 230-kV lines west of Central. The Imperial Irrigation District (IID) Board approved the Memorandum of Agreement on June 21, 2006.

The California ISO Board of Governors voted unanimously to approve the Sunpath Project (the combined Sunrise Powerlink/Green Path Project – Southwest project, see Figure 3) at its August 3, 2006, board meeting.[39]

## Figure 3. Sunpath Project




Source: California Energy Commission

SDG&E then filed an amended application, including the Proponent's Environmental Assessment, to the CPUC on August 4, 2006 (A.06-08-010). The application was deemed complete on September 8, 2006.[40] On August 31, 2006, the BLM published its Notice of Intent to prepare an Environmental Impact Statement (EIS) in the *Federal Register*. On September 15, 2006, the CPUC issued a Notice of Preparation/Notice of Public Scoping Meetings for the environmental impact report/environmental impact statement (EIR/EIS). In early October, 2006, the CPUC and BLM held a series of public scoping meetings to take public comment on the scope and content of the environmental document.[41] A recent scoping order for the Sunrise Project calls for an analysis of the full

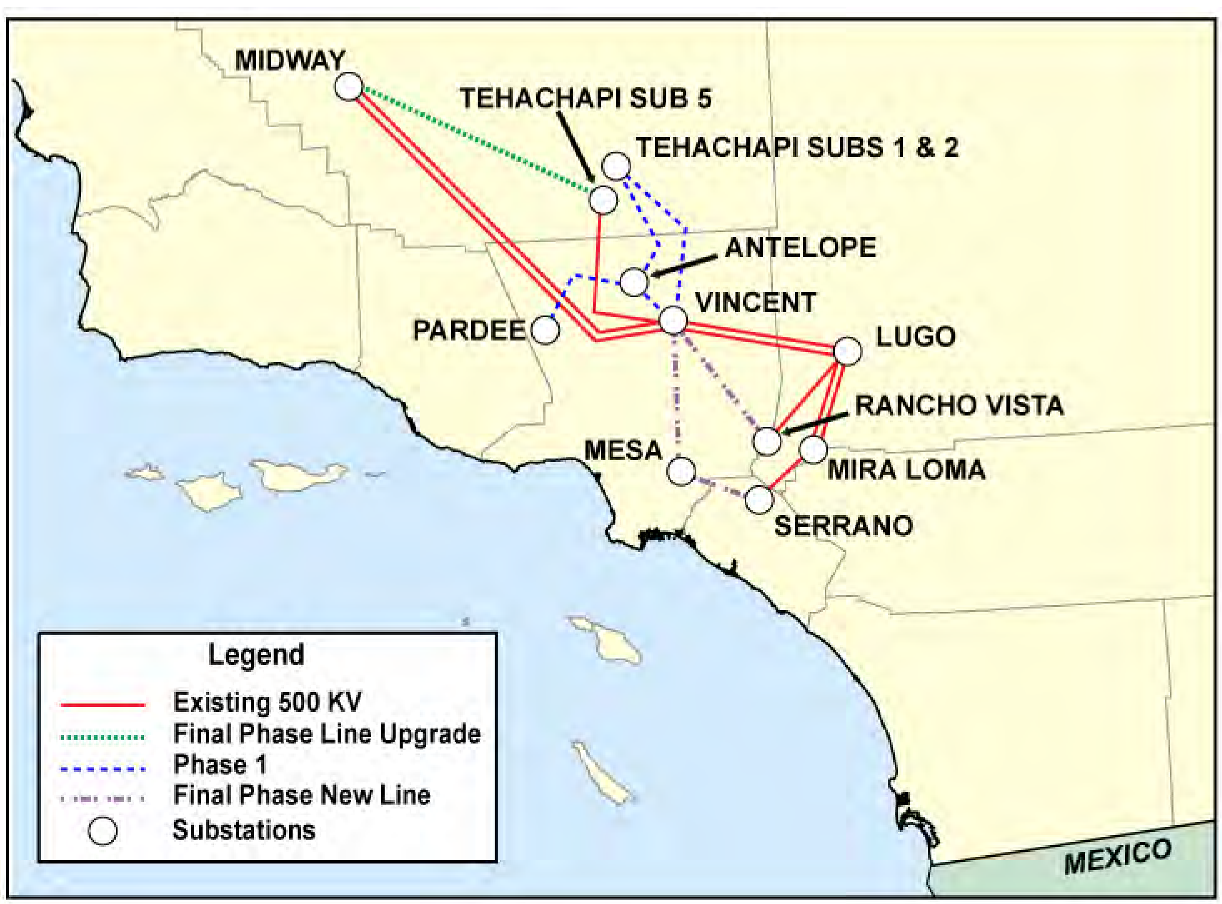
[39] See Web site http://www.caiso.com/pubinfo/BOG/minutes/docs/060803_final_boggen_minutes.pdf.
[40] See Web site http://www.sdge.com/sunrisepowerlink/info/SunriseCompleteLtr.pdf.
[41] See Web site http://www.cpuc.ca.gov/Environment/info/aspen/sunrise/sunrise.htm.

range of alternatives, including incremental energy efficiency and integrated wire and non-wire strategies.[42] This scoping order identifies a projected decision date for the CPCN of January 2008.

#### *Antelope Transmission Project*

The Antelope Transmission Project (see Figure 4, which also includes the other phases of the Tehachapi Project), proposed by SCE, is crucial to the development of wind resources in the Tehachapi region and will offer significant benefits to California. It will permit the reliable export of about 700 MW of new wind generation from the Tehachapi area.

**Figure 4. Tehachapi Project**




Source: California Energy Commission

The California ISO unanimously approved the project on July 29, 2004.[43] Phase 1 consists of three segments: Segment 1 is a new 500-kV, 25.6-mile transmission line from the existing Antelope Substation to the existing Pardee Substation, initially energized at 220

[42] California Public Utilities Commission Assigned Commissioner and Administrative Law Judge's Scoping Memo and Ruling on CPCN for Sunrise Powerlink Transmission Project, A.06-08-010, November 1, 2006.
[43] See Web site http://www.caiso.com/docs/09003a6080/32/43/09003a6080324395.pdf.

kV. The project, which would replace an existing 66-kV line, traverses about 13 miles of the Angeles National Forest. Segment 2 is a new 500-kV, 21-mile transmission line from the existing Antelope Substation to the existing Vincent Substation, initially energized at 220 kV. Segment 3 is a new 500-kV, 26-mile transmission line from the existing Antelope Substation to a new Tehachapi #1 substation, plus a new 220-kV, 10-mile transmission line from the new Tehachapi #1 substation to a new Tehachapi #2 substation.

For Phase 1, Segment 1, SCE filed an application for a CPCN with the CPUC on December 9, 2004, for the Antelope-Pardee 500-kV Transmission Project (A.04-12-007). SCE also filed an application for a 50-year special use easement to the U.S. Department of Agriculture (USDA) Forest Service. A Notice of Intent to prepare a joint EIR/EIS was issued on June 28, 2005. The joint CPUC/Forest Service draft EIR/EIS was released on July 21, 2006. The CPUC and Forest Service held public participation meetings in Southern California August 28–30, 2006. Written comments on the draft EIR/EIS were due on October 3, 2006. According to a quarterly status report from the Forest Service covering the period from April 1, 2006 to June 30, 2006, the Forest Service estimates that it will issue a decision on the special use easement in April 2007.[44]

For Phase 1, Segments 2 and 3, SCE filed an application for a CPCN with the CPUC on December 9, 2004 (A.04-12-008.) The application was deemed incomplete, so SCE then filed an amended application, along with a complete Proponent's Environmental Assessment, on September 30, 2005, replacing the original application.

The CPUC's Energy Division deemed the supplemental application complete on November 22, 2005. The draft EIR was released on August 23, 2006.[45] The CPUC held informational workshops and public participation hearings on October 11 and 12, 2006. According to an October 6, 2006, CPUC administrative law judge ruling, a final decision on the CPCN and certification of the final EIR is anticipated in February 2007.[46]

### *Imperial Valley Transmission Upgrades*

An Imperial Valley upgrade project would provide access to valuable renewable resources needed to meet future load growth, support California's RPS goals, and provide significant near-term reliability benefits to California.

IID Energy has teamed with the LADWP and Citizens Energy to create the Green Path Project, which will boost transmission capacity in both IID Energy's and LADWP's regions while facilitating transportation of Imperial Valley-produced renewable energy to the western grid.

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[44] See Web site http://www.fs.fed.us/sopa/components/reports/sopa-110501-2006-04.pdf.

[45] See Web site http://www.cpuc.ca.gov/Environment/info/aspen/atp2-3/toc-deir.htm.

[46] See Web site http://www.cpuc.ca.gov/EFILE/RULINGS/60562.pdf

The Green Path Project consists of three projects. The first arm of the project, sponsored by IID Energy, will accommodate the growing demand for energy within IID Energy's service area by upgrading the utility's existing transmission capacity from 161 kV to 230 kV. In November 2005, the IID Board approved Phase 1 (environmental, permitting, preliminary engineering, and so forth) of the Green Path Coordinated Project, which is scheduled for completion by December 2006. The third arm of the project, dubbed the Green Path Southwest Project, was described above in the "Sunrise Powerlink Project."

## Continuing Problems in Transmission Permitting and Planning

As noted in the *2003* and *2005 Integrated Energy Policy Reports*, unless California improves the current transmission planning and permitting process, longer-term renewable transmission projects will suffer from the delays and problems that plague near-term projects.

Governor Schwarzenegger recently reiterated his agreement with previous *Integrated Energy Policy Report* recommendations to consolidate generation and transmission permitting within the Energy Commission. In his September 29, 2006, veto of Assembly Bill 974 (Nuñez), which focused on additional reporting requirements under the existing CPUC transmission permitting process, he made the following statement:

> To the Members of the California State Assembly: I am returning Assembly Bill 974 without my signature. This measure focuses on the California Public Utilities Commission internal siting process, much of which the commission could do administratively without legislation. However, this measure does nothing to eliminate duplication between agencies, streamline the process, provide consistency or increase certainty. In my response to the 2003 Integrated Energy Policy Report (IEPR) I outlined a program to streamline the transmission permitting process. This proposal included consolidating transmission and generation siting in the same agency, develop a corridor planning process as proposed to be established in SB 1059 currently pending my approval, and increasing transmission investment from both the utility and merchant sector. California needs a one-stop permitting process for bulk transmission lines, which is integrated with energy planning. Agency functions would be consolidated, efficiency in state government promoted, public involvement in permitting decisions enhanced, and permitting decisions would be made in a timely manner. This bill fails to resolve the current disconnect between transmission planning and permitting and it creates duplicative filing requirements between the investor-owned utilities and the California Independent System Operator.

The Energy Commission was recently given additional transmission corridor planning and designation authority by Senate Bill 1059 (Escutia), Chapter 638, Statutes of 2006, which Governor Schwarzenegger signed into law on September 29, 2006. This new responsibility will allow the Energy Commission to work formally with federal, state, and local agencies, as well as utilities, generators, and the affected public, to set aside appropriate corridors to meet future transmission needs in the state. While this will not affect transmission lines currently in the permitting and advanced planning stages, the new corridor planning and designation process should allow future renewable transmission projects to move forward in a streamlined and efficient manner.

### *Tehachapi Transmission Plan*

The Tehachapi Transmission Plan has evolved over the last several years. The original Tehachapi Study Group Plan called for four phases of transmission projects to allow a full build-out of wind facilities to connect up to 4,000 MW of renewable resource in the Tehachapi region. While planning continues for transmission additions to accommodate the full build-out of the area, now revised up to 4,500 MW, Phase I of the plan for the Antelope Transmission Project has moved forward into permitting, as previously discussed.

A number of uncertainties still surround how and when additional transmission upgrades and additions to the Tehachapi area will be made to allow a full build-out of renewable resources in the area. The estimated on-line dates for all three phases of Tehachapi continue to be the subject of ongoing debate, as shown in Table 2. On September 19, 2006, at a presentation to the California ISO South Regional Transmission Process for 2006 (CSTRP-2006), SCE estimated the on-line date for 700 MW of wind in Segment 1 as 2009, with another 1,500 MW to be on line by 2012, and an additional 2,300 MW on-line in 2015, for a cumulative total of 4,500 MW. This included Substation 1 at Antelope and Substation 5.

The California ISO staff could present its analysis of the entire Tehachapi project to the Board of Governors in January 2007, and, as currently described, the project calls for all phases to be on line by 2010. The discrepancies on proposed on-line dates must be reconciled if these transmission projects are to move forward expeditiously into permitting and construction and be on line to help meet 2010 RPS goals.

### *Federal Transmission Corridor Planning and Permitting*

Changes in the federal landscape under the *Energy Policy Act of 2005* require the Department of Energy (DOE) to designate in 2006 transmission corridors of "national significance."[47] Under this same law, the Federal Energy Regulatory Commission (FERC) can now authorize construction of a transmission line of national significance if an

[47] Section 1221 of the Federal Power Act of 2005.

application is submitted to construct a project and the state has failed to approve a transmission project for more than one year or has conditioned its approval in a way that makes construction economically unfeasible.

## Table 2. Estimated On-Line Dates for Tehachapi

| | CPUC (8/23/2006 Workshop) | SCE (9/19/2006 at CSTRP Workshop) | California ISO (11/21/2006)[48] |
|---|---|---|---|
| Phase 1, Segment 1 | 1/2009 | 2009 (700 MW) | 12/2008 |
| Phase 1, Segment 2 & 3 | 5/2009 | | 3/2009 |
| Phase 2, Segments 4–8 | 12/2010 | 2012 (2,200 MW, cumulative) | 8/2011 (Seg. 4)<br>3/2011 (Seg. 5)<br>11/2011(Seg. 6) |
| Vincent-Mira Loma Upgrades[49] | | 2013 | 4/2012 (Seg. 7)<br>4/2012 (Seg. 8) |
| Phase 3, Segments 9–12[50] | 6/2012 | 2015 (4,500 MW, cumulative) | 9/2011 (Seg. 9)<br>10/2011 (Seg. 10)<br>11/2013 (Seg. 11)<br>(Seg. 12 not included or identified at this meeting) |

Source: California Energy Commission

In recent comments to DOE on its *National Electric Transmission Study* and possible designation of national interest electric transmission corridors, the Energy Commission, after specifically identifying a number of wilderness, park, and other sensitive areas unsuitable for corridor designation, made the following observations:

> The Energy Commission recognizes that there may be specific cases where federal back-stop siting authority might be justified and welcomed on a case by case basis. The lack of timely permitting for transmission in California continues to be of concern to the Energy Commission. While the state will not easily cede its sovereignty over land-use decisions relating to transmission development in California, in cases of national significance where the State has been unable to make progress in approving vital transmission projects, federal back-stop siting would be

[48] http://www.cpuc.ca.gov/static/Energy/sce's%2011-21-06%20workshop%20presentation%206.pdf.

[49] Southern California Edison introduces a new Phase 3, thus turning the project into a 4-phase proposition. The additional "phase" is the South of Vincent line upgrades. These actually have no direct bearing on Tehachapi, but Southern California Edison claims it is needed to send power south. At the time of this writing, this phase includes: Vincent – Mira Loma 500 kV line; Reconfigure Vincent 500 kV bus; and Reconfigure Mira Loma 500 kV bus.

[50] Per Presentation by Tom Flynn, 8/23/2006 California Public Utilities Commission Workshop.

beneficial. DOE should focus its efforts on how such a process would be coordinated with state and regional entities.

The Energy Commission continues to be an active participant in the federal corridor designation process also called for under section 368 of the *Energy Policy Act of 2005*. Under this section of the law, the secretaries of agriculture, commerce, defense, energy, and the interior are directed to designate under their respective authorities corridors on federal land in 11 western states. In late 2005, the BLM and DOE designated the Energy Commission as a "cooperating agency" in the federal programmatic environmental impact statement effort for energy corridors in the Western states, under section 368 of the *Energy Policy Act of 2005*. The Energy Commission's role in this federal proceeding is to ensure that the state's energy and infrastructure needs, renewable generation policy goals, and environmental concerns are considered in the programmatic environmental impact statement. Continued coordination between the Energy Commission and federal agencies will be critical in addressing future renewable transmission needs.

## Cost Allocation Issues for Renewable Transmission

Cost allocation issues pose a major barrier to developing transmission infrastructure to access remote renewable resource areas. The *2005 Integrated Energy Policy Report* concluded that "without major transmission infrastructure investment, California will not be able to reap the benefits of some of the state's most promising areas for renewable generation: the Tehachapi and Imperial Valley areas."[51]

As noted in the *2005 Integrated Energy Policy Report*, FERC did not approve SCE's trunkline proposal for Segment 3 of Phase 1 of the Tehachapi Transmission Plan Project for treatment as a network upgrade. Consequently, although FERC treated Segments 1 and 2 of Phase 1 of that project as network facilities, and transmission rates were allowed to be allocated to all California ISO participants, the pivotal segment which would link major concentrations of renewable energy resources to the California ISO-controlled grid was not allowed rolled-in rate treatment. As a result, the Energy Commission reiterated its 2003 recommendation for changes to the California ISO tariff to recognize a third category of transmission facilities that would encourage renewable transmission development.[52]

In attempting to move forward on renewable transmission, including Segment 3 of the Tehachapi Transmission Project, on June 15, 2006, the CPUC issued a decision on procedures to implement the cost recovery provisions of Public Utilities Code section 399.25, enacted as part of SB 1078, which is intended to facilitate California's access to

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[51] California Energy Commission *2005 Integrated Energy Policy Report,* November, 2005. p. 91.

[52] California Energy Commission, *2005 Integrated Energy Policy Report,* November, 2005, p. 100.

renewable energy resources.[53] This statute provides a "back-stop" cost mechanism allowing utilities to recover through retail rates any costs of transmission projects "necessary to facilitate achievement of the State's RPS renewable power goals" that are not approved by FERC for recovery through transmission rates.[54]

Over the last several months, the California ISO has been working on a proposal to move forward with tariff changes that would recognize a third category of transmission facilities for remotely located resources such as renewables. The California ISO recognizes that the production of electricity through wind, solar, biomass, and other technologies is limited to certain geographical regions with very little nearby land, but vast potential for renewable energy supply.[55] The California ISO also notes that the CPUC "back-stop" cost recovery for renewable transmission establishes an inconsistent framework among federal and state regulators that could delay development of renewable generation.[56] The California ISO recognizes that power plants in these remote regions typically require long high-voltage transmission lines to interconnect to the high-voltage transmission grid. Beginning in June 2006, the California ISO proposed and has refined a general framework for new evaluation criteria for certain transmission projects that are not considered "network upgrade" facilities. The California ISO has also proposed alternative treatment for the costs associated with this type of transmission project.

On October 19, 2006, the California ISO Board of Governors unanimously agreed to file a petition for a Declaratory Order with FERC on a policy to facilitate financing and construction of transmission facilities necessary for efficient development of renewable resources in remote locations. This new proposal seeks policy guidance from FERC regarding tariff changes that would allow the California ISO to evaluate and approve transmission facilities sized adequately to enable efficient development and marketing of power generated in a remote region. The costs of the transmission project can be recovered over time from transmission system users and from generators as they connect to the lines in the future. If FERC grants the declaratory order, the California ISO will conduct a stakeholder process to obtain additional input and then file detailed tariff language with FERC.

The Energy Commission strongly supports the California ISO's approach for addressing renewable transmission investments. FERC should not adhere rigidly to past definitions and ratemaking practices developed in other contexts and for other purposes. Doing so will foreclose the innovation needed to bring new renewable resources to the market

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[53] California Public Utilities Commission Decision 06-06-034 in Order Instituting Investigation 05-09-005, Interim Order on Procedures to Implement the Cost Recovery Provisions of Public Utilities Code section 399.25, June 15, 2006.

[54] California Public Utilities Commission Decision 06-06-034.

[55] *Proposal to Remove Barriers to Efficient Transmission Investment*, California Independent System Operator white paper, revised September 21, 2006, p. 3.

[56] Ibid, p. 10.

using newly constructed or upgraded transmission infrastructure to address existing constraints.

## *Financeability of Supplemental Energy Payments*

Another impediment to achieving the 2010 goal is the uncertainty regarding the financeability of SEPs. Although no SEPs have been awarded to date and only two projects have identified a need for them, market participants anticipate that SEPs will not be viewed as secure enough to provide a basis for project financing because lenders need assurance of a long-term commitment to pay. Because of State of California administrative processes, there is no such assurance that SEPs will be available for the full term of the SEP award.[57] The uncertainty over future payment of SEPs may make project financing either impossible or—as is more likely—more expensive than if SEP funding were more certain. In the former case, achievement of the state's renewable energy targets may be jeopardized. In the latter case, the draw on SEP funds may be higher than if SEPs could be more reliably disbursed.

Funds earmarked for clean energy development in a number of states, including California, have in the past been re-appropriated or borrowed for other purposes by state legislatures, giving real weight to these concerns.

Stakeholders raised this issue at the *2006 Integrated Energy Policy Report Update* workshops on the midcourse RPS review, stating that the Energy Commission must provide better assurances that SEP funding will be available for SEPs to serve their intended purpose and result in the development of new renewable energy facilities.

In its written comments for the August 22, 2006, workshop, PG&E stated:

> Inability to finance projects based on revenue streams funded by SEPS is one of the most significant barriers to development of renewables, along with uncertain availability of tax credits, lack of transmission, and the scarcity of equipment….PG&E urges the Commission to address the role of SEPs and to propose, by legislation if necessary, the means to make SEPs financeable so that the public good charge will actually be used to promote the development of renewable energy central generating resources.

The Green Power Institute also addressed this issue in its written comments for the August 22, 2006, workshop:

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[57] Public Resources Code section 25743 subparagraph (b)(1)(C) as amended by Senate Bill 107 (Simitian), Chapter 464, Statutes of 2006, states: supplemental energy payments shall be paid for no longer than 10 years, but shall, subject to the payment caps in subparagraph (A), be equal to the cumulative above-market costs relative to the applicable market price referent at the time of initial contracting, over the duration of the contract with the retail seller or procurement entity.

> Commissioner Geesman has stated in a variety of venues, including at the July 6 workshop in this proceeding, that SEPs are inherently un-financable,[sic] because they cannot be guaranteed. We believe that the problem is deeper still. Even if SEP funds could be securely escrowed, the fact remains that the generator has to go through the cumbersome process of dealing with two separate, sequential applications, first the utility's RPS solicitation, then the [Energy Commission's] SEP process, and ultimately two different contracts, often with different contract terms (e.g. 20–yr PPA, 10–yr SEP), and other differences. This is not a straight line to putting renewable power on the grid.
> …

The initial SEP applications will provide a test of financeability of the MPR/SEP structure. Future demand for SEPs is difficult to predict, but either lower future MPRs or escalating costs for renewable generation could result in more RPS bids that require SEPs to come on line.

Under the *New Renewable Facilities Program Guidebook*, SEPs will be awarded to winning bidders of RPS solicitations through grant agreements that legally encumber SEP funds for the bidder and the bidder's project. Grant agreements will include standard termination provisions allowing the Energy Commission to terminate the agreement for reasonable cause, including insufficient monies in the Renewable Resource Trust Fund to adequately fund the grant agreement. The latter is included in recognition of the fact that the Legislature may borrow or reallocate money from the Renewable Resource Trust Fund for other purposes. If this occurs, the Energy Commission must have recourse to terminate or reduce the amount of the grant agreement because of inadequate funding.

To comply with the California Environmental Quality Act, the Energy Commission will formally approve grant agreements only after a project has completed its required environmental review. Funding Confirmation Letters will be issued to winning bidders prior to this time to inform bidders of the SEP funds that have been reserved by the Energy Commission for the bidder's project. Funding Confirmation Letters will identify the total amount of the SEP award, but will not provide specifics on the production incentive level, payment term, or other project information which may be designated confidential at that point in the project's development.

### *Complexity and Lack of Transparency in the Renewable Portfolio Standard Process*

The *2005 Integrated Energy Policy Report* identified the lack of transparency in bidding, ranking, and contracting processes as among the main problems in need of correction in the RPS program. Data confidentiality and lack of clarity in the RPS program undermine public confidence that the state is truly on track to meet the 20 percent by 2010 goal.

Major problems include the lack of public information in the least-cost, best-fit process used to rank renewable bids, the process used to develop the market price referent, and confidentiality concerns surrounding bid data needed by the Energy Commission to process and determine SEP awards.

## Least-Cost, Best-Fit Process

California's utilities have been given an extraordinary level of discretion in designing their RPS procurement plans, particularly in their least-cost, best-fit methodologies. The CPUC's Decision 06-05-039 first conclusion of law states: "Electrical corporations should be given flexibility in the way they satisfy RPS programs, subject to Commission guidance, limited specific program requirements, and a specific timeframe for the next solicitation."[58]

As noted in the *2005 Integrated Energy Policy Report,* the least-cost, best-fit method that IOUs use to rank RPS bidders is particularly unclear. The intent of the least-cost, best-fit process was to allow the IOUs to select renewable projects that met their obligation while taking into consideration the utilities' specific resource needs as well as the cost of the projects. The "least-cost" element helps minimize cost impacts on utility ratepayers of procuring renewable energy. The CPUC defines "best fit" as "the renewable resources that best meet the utility's energy, capacity, ancillary service, and local reliability needs."[59]

Each IOU has its own distinct least-cost, best-fit approach, but it is not clear that these disparate approaches match well with overall state costs and resource needs, given the RPS goals. As noted in the *2005 Integrated Energy Policy Report*, descriptions provided by the IOUs on their least-cost, best-fit criteria require a high degree of interpretation and judgment. The application of these criteria in bid selection is known only to utilities and individuals participating in select procurement review groups—membership in which is limited to non-market participants willing to sign non-disclosure agreements—making it difficult for policy makers to determine whether IOUs are selecting projects that are truly least-cost and best aligned with the state's policy to provide long-term benefits to the system.

Under current confidentiality constraints, Energy Commissioners—who ultimately make decisions about the expenditure of public funds for projects requiring SEPs—are unable to review or scrutinize detailed information about the application of least-cost, best-fit criteria used to select renewable projects unless they sign non-disclosure

[58] California Public Utilities Commission, D.0605039, Rulemaking 04-04-026 *Opinion Conditionally Approving Procurement Plans for 2006 RPS Solicitations, Addressing TOD Benchmarking Methodology, and Closing Proceeding,* May 25, 2006.

[59] California Public Utilities Commission, June 19, 2003, Decision 03-06-071, *Order Initiating Implementation of the SB 1078 Renewable Portfolio Standard Program*, p. 28 [http://www.cpuc.ca.gov/word_pdf/FINAL_DECISION/27360.pdf], accessed April 19, 2005.

agreements. Despite the fact that Energy Commissioners have reluctantly signed these agreements to ensure there are no delays in processing the first two SEP requests, neither PG&E nor SDG&E has yet provided the necessary information five months and seven months, respectively, after submitting contract advice letters to the CPUC. [60]

In addition, there is an imbalance of information in the current solicitation process. Bidders do not have adequate knowledge of the least-cost, best-fit criteria by which their bids will be evaluated, making it difficult to determine how or even whether to bid in any solicitation. The California Wind Energy Association raised this concern, stating, "We think it would help a lot if utilities provided some very detailed examples about how the least-cost/best-fit process works so we can have a better understanding and there can be a little less secrecy."[61] In contrast, the IOUs, as monopoly buyers within their service territories, not only know what resources best fit their needs but also receive cost information in the bids of all sellers. Because IOUs can construct their own RPS generation facilities, they have detailed information about market prices and terms not available to their competitors.

Recent decisions at the CPUC represent important progress in addressing the lack of information regarding the least-cost, best-fit evaluation process. In Rulemaking 06-04-027, the scoping memo reiterated the requirement for the three large IOUs to report on their project evaluation process, as order in Decision 06-05-039. The scoping memo added additional urgency, stating, ". . . each IOU should submit its first evaluation criteria and selection report on a more advanced schedule." IOUs and ESPs filed initial project evaluation and selection reports on September 29, 2006. The reports provide considerable detail as to ranking, capacity costs, congestion, and the incorporation of transmission costs. The CPUC held a workshop December 15, 2006, to discuss the reports and areas where further transparency may be needed.

In addition, Decision 06-06-066 on confidentiality[62] recognized the strong public interest in renewable resources and the need for more openness in the process used to select those resources. The decision implements SB 1488 (Bowen), Chapter 690, Statutes of 2004, which requires that the CPUC examine its practices regarding confidential information to ensure meaningful public participation and open decision making, in the context of earlier statutory responsibilities to protect certain information.

The CPUC decision clearly states that the burden of proof that information should be confidential rests on the party seeking confidentiality protection. It also concludes that

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[60] California Public Utilities Commission, Resolution E-4022, November 30, 2006, http://www.cpuc.ca.gov/Published/Final_resolution/62658.htm, and San Diego Gas and Electric, Advice Letter 1795-E, May 22, 2006.

[61] Testimony of Nancy Rader, California Wind Energy Association, transcript of the July 6, 2006 Integrated Energy Policy Report Committee workshop, p. 86.

[62] California Public Utilities Commission Decision 06-06-066, Rulemaking 05-06-040 *Interim Opinion Implementing Senate Bill No. 1488, Relating to Confidentiality of Electric Procurement Data Submitted to the Commission*, June 29, 2006.

"greater public access should be provided for procurement documents relating to the RPS program because of the public interest aspects of the program." Furthermore, the CPUC rejected IOU arguments that all procurement-related information should be confidential and explains that only material information can be deemed market sensitive.

The CPUC noted that Public Utilities Code section 399.14(a)(2)(A) provides confidentiality for the results of a competitive solicitation only until the solicitation is complete, which "is a very narrow confidentiality requirement that does not change our general conclusion that most RPS information should be public." The CPUC's stricter standards for proving the need for confidentiality may help open the process.

## Market Price Referent, Natural Gas Forecasts, and Time of Delivery Factors

The RPS statute requires the CPUC to establish a benchmark price of energy that is then used to determine the above-market costs of meeting the RPS.[63] Under the statute, if there are insufficient supplemental energy payment funds to cover those above-market costs, the CPUC can allow electrical corporations to limit their RPS procurement based on available SEP funds. The intent of this provision is to provide cost control for the RPS program and protect ratepayers from the potentially higher costs of procuring renewable energy.

The method for determining the MPR is essentially a stand-alone incremental engineering calculation of the future cost, in dollars per kWh, of electricity from a new baseload proxy natural gas-fired combined cycle generation plant. It represents a set of values of the levelized cost of a kWh of electricity produced at the proxy facility, adopted for a given year's RPS solicitations. It completely ignores the cost of generation from the existing fleet of aging, inefficient steam boilers (a prominent subject of the *2005 Integrated Energy Policy Report*), let alone any evaluation of ratepayer exposure to natural gas price volatility in the existing portfolio.

The MPR for a particular contract depends on contract length and contract start date. For example, in the 2005 RPS solicitations, the CPUC calculated 21 MPRs that varied from $0.07594 to $0.08429 per kWh, with the MPR for a 20–year contract starting in 2007 being $0.08098 per kWh.

### *Natural Gas Forecasts in Calculating the Market Price Referent*

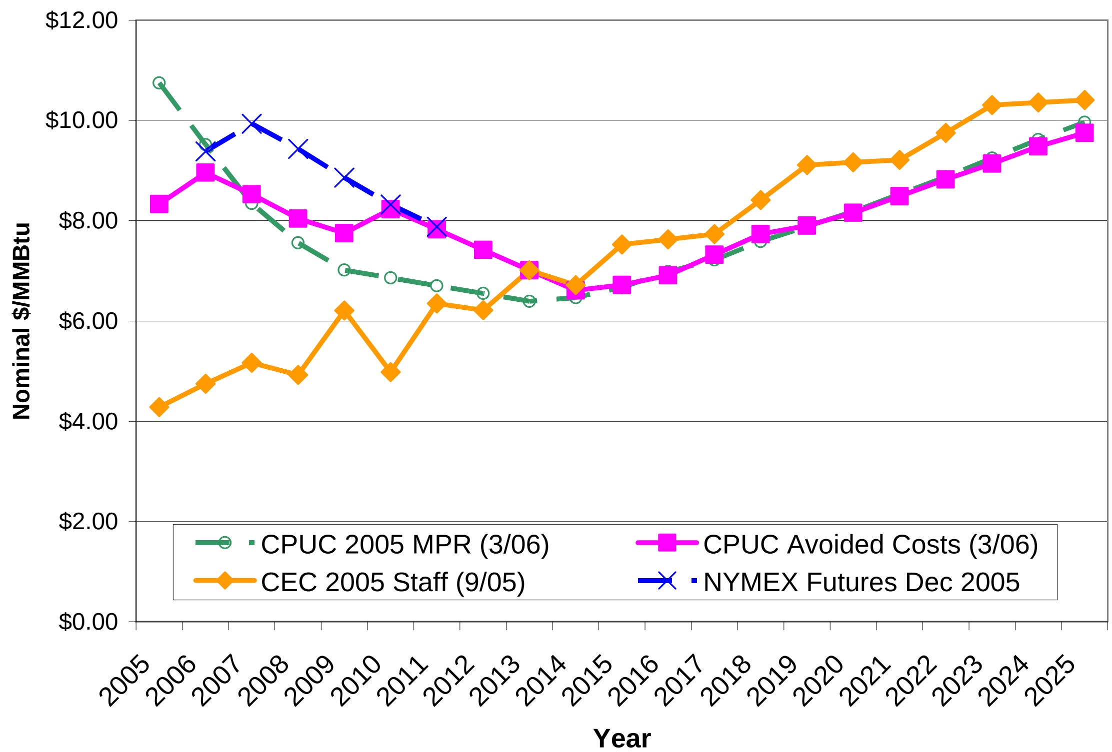
While natural gas forecasts are an essential part of the MPR calculation, the way natural gas forecasts are used to establish the MPR is problematic. The best assumption about all forecasts for commodities as volatile as natural gas is that they will be wrong. The

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

experience with gas price forecasts since 2002 has made this a truism. Because natural gas prices represent approximately 70 percent of the MPR calculation, contract prices for renewable generation depend heavily on the natural gas forecast used to calculate the MPR. There is great variability among gas forecasts in general, especially those of different vintage, but even worse between forecasts used in different CPUC proceedings to implement various aspects of state energy policy.

Figure 5 compares forecasted gas prices used in the MPR and avoided cost proceedings with an in-house Energy Commission staff forecast. Short-term forecasts are often market based, whereas longer-term forecasts rely more heavily on fundamentals, building in assumptions about the speed with which liquefied natural gas and North American supplies can be brought to market.

**Figure 5. Comparison of Natural Gas Forecasts**

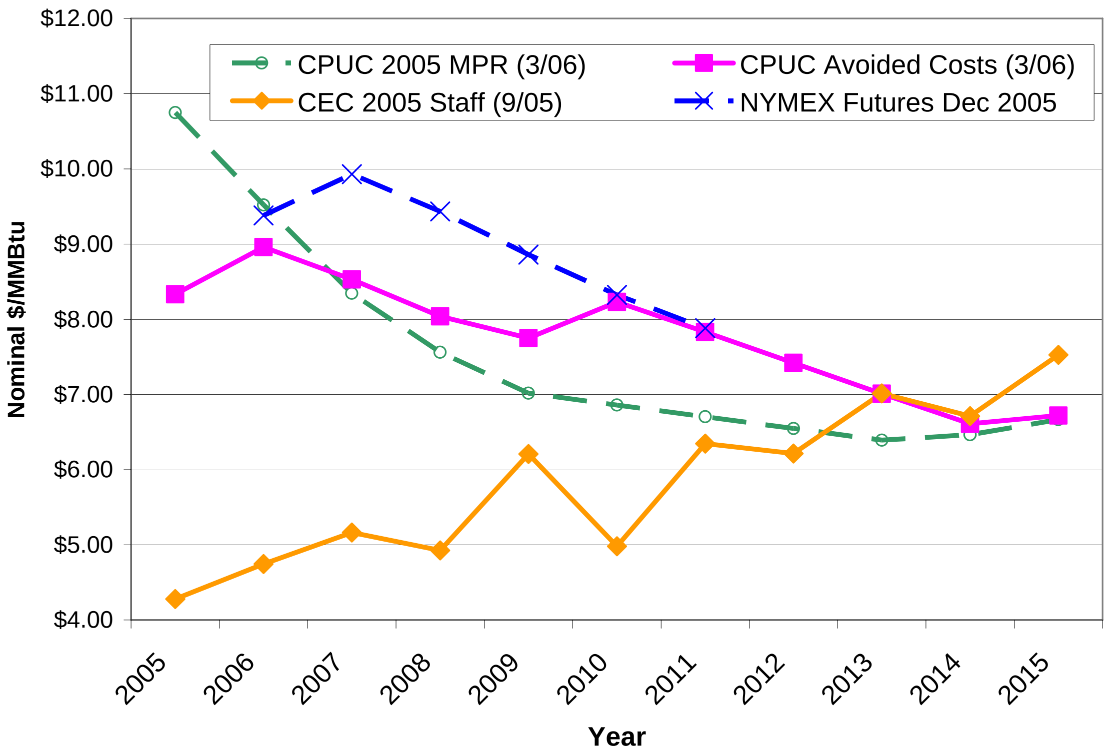



Source: Presentation by Richard McCann at 2006 Integrated Energy Policy Report Midcourse Review Committee workshop, August 22, 2006, *Comparison of Natural Gas Price Forecasts*

At a minimum, the state should use gas price forecasts for the MPR calculation that are consistent with forecasts used for procurement of other resources, including loading order resources. Otherwise, renewable resources will be over- or under-valued, which will in turn distort pricing signals necessary to promote a competitive renewable industry in the long run. More importantly, current MPR methodologies systematically

fail to recognize the hedging value of renewable resources when compared with fuel-intensive generation options like combined cycle gas-fired power plants.
Figure 6 isolates the first 10 years of the forecasts graphed in Figure 5 to illustrate the extreme divergence of projections that drive different aspects of state energy policy in contradictory directions.

**Figure 6. Comparison of Natural Gas Forecasts, Detail**



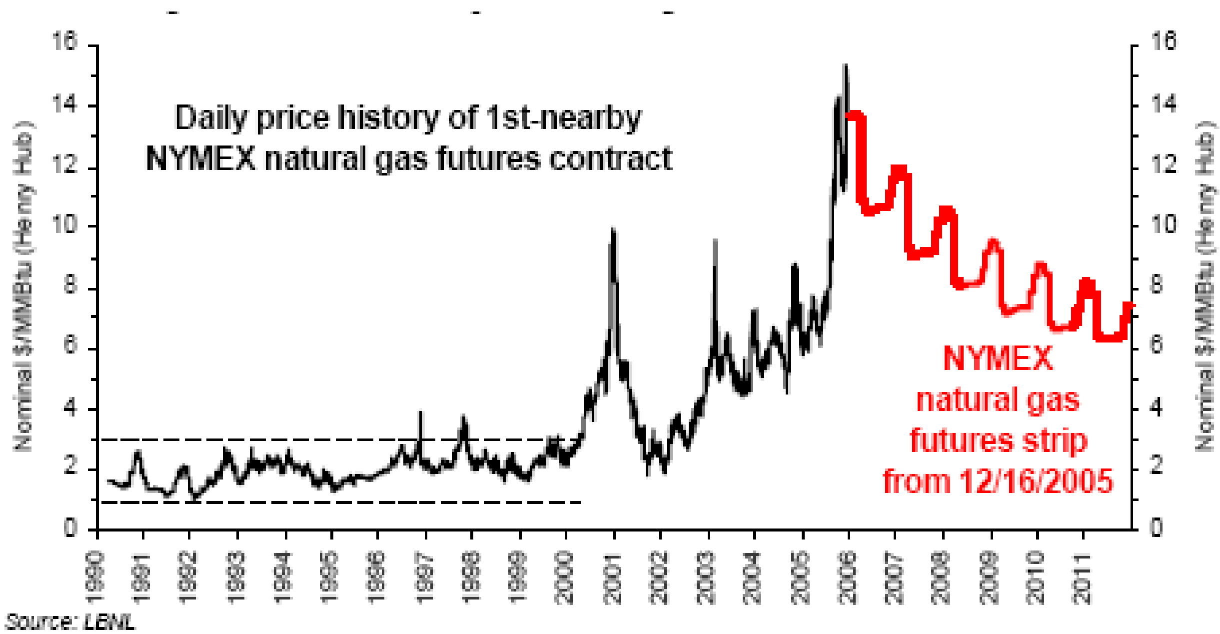

Source: Presentation by Richard McCann at 2006 Integrated Energy Policy Report Midcourse Review Committee workshop, August 22, 2006, *Comparison of Natural Gas Price Forecasts*

The CPUC avoided cost forecast is used in determining the value of energy efficiency measures. Although the MPR and avoided cost forecasts converge after 2015, predicted costs in the short term vary by as much as $1.00 per million Btu, while the Energy Commission staff forecast is as much as $4.00 lower.

In addition, given the extreme volatility of natural gas prices, tying renewable energy investments to a single snapshot of future costs, or average of these forecasts, is illogical from the point of view of modern finance theory. The current approach fails to take into account the risk associated with volatile fuel prices and does not properly reflect the RPS statute's requirement for a fixed-price long-term cost. Unlike generation from conventional fuels, costs for electricity from most renewable technologies (other than biomass projects) are driven primarily by capital investment during development stage and are not subject to fuel price volatility.

Natural gas prices fluctuate widely and unpredictably over time. As shown in Figure 7, from July 2004 to November 2006, prices varied by nearly 200 percent, with variations of more than 50 percent in a single month. Future prices shown are based on commodity trading prices at the end of 2005. These prices tend to move with current changes in the market and generally reflect higher winter demand for natural gas.

**Figure 7. NYMEX Natural Gas Futures Closing Price**




Source: Mark Bolinger and Ryan Wiser, Lawrence Berkeley National Laboratory, memorandum re: Comparison of AEO 2006 Natural Gas Price Forecast to NYMEX Futures Prices, December 19, 2005.

The role played by natural gas prices in determining whether state incentive payments are needed illustrates the futility of attempting stand-alone engineering calculations rather than the portfolio evaluation taught as standard finance theory for the past 25 years.[64] Instead, it is now common practice to value investments using a version of the capital asset pricing model (CAPM) developed in the 1960s by Nobel Laureate William Sharpe and Jon Lintner.[65]

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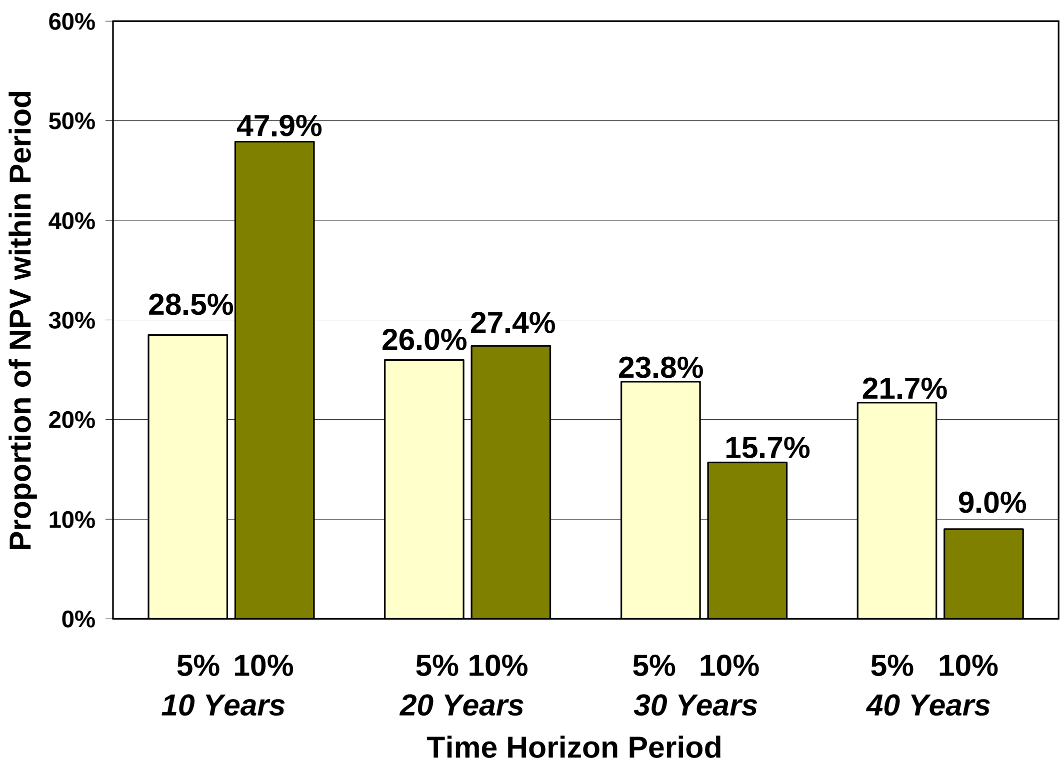
[64] Awerbuch, Shimon. *The True Cost of Fossil-Fired Electricity in the EU: A CAPM-based Approach,* January 2003, at http://www.london.edu/assets/documents/PDF/2.3.3.7.10_ otm_seminar_true_cost_of_fossil_elecricity.pdf .

[65] The Capital Asset Pricing Model quantifies and monetizes systematic risk as an empirically derived β factor that weights the value of the difference between a diversified portfolio market rate of return and the return on a risk-free investment. Recent estimates have determined βs for natural gas prices that are negative or zero, meaning that future prices should be discounted at low rates, equivalent or below the rates of return on risk-free investments like government bonds. As a result, discount rates for fuel costs should be below the post-tax yield on government bonds.

Furthermore, modern models place a different discount value on various inputs—based on risk—rather than a "one-size-fits-all" approach. Applying appropriate discount rates to capital, fuel, and operating and maintenance components of a combined cycle gas turbine plant can result in cost estimates for fossil generation that are twice as high as those made using a model based on utility discount rates.[66]

The way the present value cost of future gas deliveries is distributed among future time periods is strongly dependent on the discount rate used in the present value calculation, as shown in Figure 8.

**Figure 8. Influence of Discount Rate on Present Value Cost Distribution over Planning Horizon (with 0% Escalation Rate)**




Source: Presentation by Richard McCann at Integrated Energy Policy Report Committee workshop, *Midcourse Review of the Renewables Portfolio Standard,* August 22, 2006, *Comparison of Natural Gas Price Forecasts*

Each utility uses its own weighted average cost of capital as the discount rate for evaluating procurement contracts, and the SEP payments are also based on each utility's distinct discount rate. The 2005 MPR is calculated using a discount rate (weighted

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[66] Awerbuch, Shimon. *A Brief Overview of Wind Economics in the 21st Century*, November, 2005, at http://www.awerbuch.com/shimonpages/shimondocs/Wind_Econ_overview.doc.

average cost of capital) that uses "the cost of capital of industrial companies in the Standard and Poor's (S&P) 500 index and risk profiles comparable to that of the independent power generation industry as a whole."[67]

Figure 8 illustrates that, with a 10 percent discount rate, nearly half of the future value of a natural gas contract comes from the first 10 years, while only 28.5 percent of total value comes from the first 10 years with a 5 percent discount. Discount rates used by the IOUs in the 2005 RPS solicitation and the discount rate for MPR calculation are all close to 8 percent. This means that gas prices over the first 10 years of the contract determine most of the value of a contract for future natural gas, and prices in the later years of a 15- or 20-year contract are less important. This indifference to future price volatility locks ratepayers into a growing dependence on natural gas as a source of electricity generation, a major theme of the *Integrated Energy Policy Reports* in both 2003 and 2005.

### *Time of Delivery Factors*

A further complication in the calculation and application of MPRs is that each utility develops its own time of delivery (TOD) factors that value generation based on when it is delivered by season and time of day. Once TOD factors are applied to the MPR, each project ends up with a specific and unique MPR based on its delivery profile. These appear to be extremely subjective.

SCE's 2005 summer on-peak TOD factor is more than double its 2004 TOD factors and also more than double a similar factor used to determine payments to qualifying facilities already under contract. SCE's 2005 summer on-peak TOD factor is nearly twice SDG&E's and almost 70 percent higher than PG&E's. The differences are due to the fact that utilities may value peak power differently depending on the "peakiness" of their load and the location of the generation with respect to loads that face congestion problems. However, according to the IOUs' descriptions of their methodologies, it appears that the most important reason for the differences is the method used to value capacity. A second important reason is the difference in the number of hours in the Summer Peak period between utilities.

The methodologies used by the IOUs to calculate their TOD factors are unclear and appear to be inconsistent. An August 2006 Energy Commission consultant report compared and contrasted what is known about each IOU's methodology. SCE is the only IOU that allocates capacity value to its TOD factors using loss of load probability (LOLP) factors developed in its general rate case. These factors are not specific to the technology being considered, but instead represent the likelihood that load would be curtailed due to insufficient supply during any hour or time period. The factors are therefore a proxy for buying expensive power on an hour- or day-ahead basis during peak periods.

[67] California Public Utilities Commission, Resolution E-3980, *2005 Market Price Referents*, April 13, 2006.

In contrast, PG&E calculates a net capacity cost based on the cost of a new combustion turbine. PG&E calculates a combustion turbine's net energy benefit as the difference between revenues and the variable costs incurred to earn the revenues. For each time period, PG&E calculates the net capacity cost as the amount by which the combustion turbine's real economic carrying charge exceeds its net energy benefits. These net capacity costs for each time period weight the full TOD factor for the period. The formulas and quantitative inputs for this calculation have not been made public by PG&E.

SDG&E did not use TOD factors in the 2004 RPS solicitation and did not use separate energy and capacity weightings in development of TODs for the 2005 solicitations.

The IOUs have not sufficiently explained or justified the choice of methodology used to develop their TOD factors. During the development of the 2006 RPS solicitations, the CPUC requested that IOUs propose a uniform benchmarking methodology for TOD factors. In its decision conditionally approving the IOU's 2006 RPS procurement plans, the CPUC did not reject any specific TOD factors, but stated, "We are not convinced, however, that any benchmarking proposal is sufficiently developed, documented, or explained to be explicitly endorsed or adopted by us at this time." The Energy Commission encourages the CPUC to continue efforts to standardize and clarify the methodology for developing TOD factors.

The result of these different methodologies is an unnecessarily complex market for bidders in which different utilities pay very different prices for the same generation profile. Furthermore, the lack of transparency of the TOD calculations could lead to gaming of SEP payments. By manipulating a generation profile, a bidder could change the amount of SEPs required or the apparent value of its expected generation. An IOU could also choose lower or higher TOD factors which, in turn, would change the portion of the contract paid by the IOU and the amount of SEPs for which a project is eligible.[68] Because the IOUs have not been sufficiently forthcoming in the process used to determine these TOD values, it will be difficult to determine if such gaming occurs.

## Impact of Data Confidentiality on Supplemental Energy Payments

Another area where data confidentiality can potentially slow down the RPS process is in the processing of SEP applications to cover above-market costs. The Energy Commission is responsible for awarding SEPs to renewable facilities that are selected by the IOUs in their solicitations at costs greater than the MPR. As noted above, it is extremely difficult to predict the above-market costs of these contracts due to variability in natural gas prices and uncertainty about which technologies will be selected as least-cost, best-fit. To

[68] California Energy Commission, staff presentation. Integrated Energy Policy Report Committee Workshop on Midcourse Review of the Renewables Portfolio Standard Process. August 22, 2007.

prevent prematurely exhausting the public funds set aside to help achieve RPS goals and to guard against gaming, the Energy Commission must have access to market data on which to base decisions regarding funding awards. However, this information is currently available only to IOUs, the CPUC, or to members of the confidential procurement review groups.

The Energy Commission's *2006 Renewable Energy Investment Plan (Investment Plan)* contained scenarios for allocating SEPs based on the IOUs needing an estimated 35,000 GWh of additional renewable generation in 2010 to meet RPS goals. Based on assumptions of the capacity factors of the various renewable technologies, the *Investment Plan* found that setting a cap of 1.5 cents per kWh could result in funds being exhausted before the RPS goals are achieved. The scenarios also showed that SEP funds could be adequate if a large portion of signed contracts resulted in delivered energy before 2010, or if only a small portion of the remaining energy needed SEP support.

To provide decision makers with the most accurate market information on which to base their SEP decisions, SEP applications require the IOUs to provide bid-specific data. Although the Energy Commission's guidelines for awarding SEPs were developed through an extensive public process and are clear about the types of data needed to make award determinations, the IOUs have been reluctant to provide these data. To date, the Energy Commission has received partial SEP applications from both PG&E and SDG&E. However, SDG&E has been unwilling to provide the necessary information to support the SEP application of its one potential contract. In its response to Energy Commission staff requests for bid-specific data, SDG&E states:

> ….as we have noted previously in comments filed with this Commission, SDG&E objects to the requirement that it provide detailed bid information, including information concerning bids below the MPR, on the grounds that such requirement is unreasonable and overbroad. As the rationale for this requirement, the CEC states that it must 'make informed and timely decisions in evaluating SEP requests.' As SDG&E noted in comments filed with the CEC at the time it was considering adoption of this requirement, the CEC's reasoning implies an intent to engage in a qualitative analysis of bids received and contracts entered into by the utilities that is outside the scope of the CEC's responsibilities under the RPS program. This review is instead to be conducted by the California Public Utilities Commission (the "CPUC"). In fact, the CEC is statutorily required to award funds for projects approved by the CPUC, subject to only narrow criteria. Those criteria do not include an assessment of other bids for which applications for funds have not been made. Further the CEC staff has access to all information related to SDG&E's consideration of bids and contracts through its involvement in SDG&E's Procurement Review Group

> ("PRG"). To the extent the request for bid data as it is currently crafted exceeds the Commission's jurisdiction, it is not enforceable.[69]

The Energy Commission recognizes that some data need to remain confidential and has a formal process by which parties can request confidentiality. After legal review, the Energy Commission granted portions of SDG&E's data confidentiality request for its SEP application. Nonetheless, SDG&E and PG&E have both failed to provide complete data for below- and above-market bids, which are required under the Energy Commission's SEP guidelines.

### Renewable Contract Failures and Delays

A contractor report prepared for the Energy Commission in 2005 identified renewable energy contract failure as a potentially significant impediment to achieving the state's aggressive renewable energy goals.[70] A subsequent report summarized potentially relevant experience with renewable energy contract failure based on a contract sample of more than 21,500 MW of renewable energy capacity.[71] The data suggest that a minimum overall failure rate of 20 to 30 percent should generally be expected for large solicitations conducted over multiple years. The likelihood of much higher failure rates is supported by historical experience, especially for projects that use technologies that have yet to be proven commercially or—like many projects in California—are likely to face siting, permitting, resource supply, or transmission barriers. Data on renewable contract failure documented by North American utilities show that of 2,857 MW from 74 signed renewable contracts, 36 contracts for 1,337 MW have been canceled, delayed, or gone into default.[72] Thus, just over half appear to be successful.

Although contract failure has been common for renewable resources, the IOUs do not seem to be adequately planning for contract failure in their contracting procedures. In oral comments at the July 6 workshop on the RPS midcourse review, PG&E stated, "No additional steps are needed to trigger utility procurement in the event of contract failure," adding that "our experience for the last several years is that we have had very little contract, if any, I can't recall any contract failures."[73]

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[69] Letter from Vincent Bartolomucci, San Diego Gas and Electric Company, to Bill Knox, California Energy Commission, August 10, 2006.

[70] *Preliminary Stakeholder Evaluation of the California Renewables Portfolio Standard*. CEC-300-2005-011. Prepared by Ryan Wiser, Kevin Porter, and Mark Bolinger. June 2005.

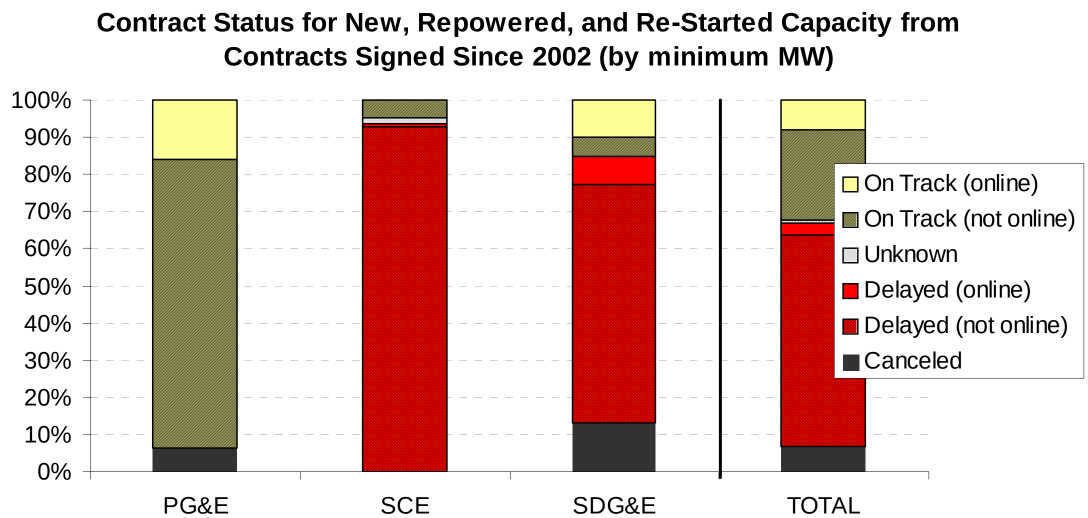
[71] *Building a Margin of Safety into Renewable Energy Procurements: A Review of Experience with Contract Failure.* CEC-300-2006-004. Prepared by Ryan Wiser, Ric O'Connell, Mark Bolinger, Robert Grace, and Ryan Pletka. January 2006. http://www.energy.ca.gov/2006publications/CEC-300-2006-004/CEC-300-2006-004.PDF.

[72] California Energy Commission, January 2006, *Building a Margin of Safety into Renewable Energy Procurements: A Review of Experience with Contract Failure.* Consultant report. CEC-300-2006-004. Prepared by Ryan Wiser, Ric O'Connell, Mark Bolinger, Robert Grace, and Ryan Pletka.

[73] Written and oral comments from Pacific Gas and Electric Company at the Integrated Energy Policy Report Committee workshop, Midcourse Review of the Renewables Portfolio Standard, July 6, 2006.

Figure 9 shows that, on a capacity basis, 7 percent of PG&E's renewable projects have been cancelled while SDG&E has experienced project cancellations of 13 percent. More significantly, project delays have affected 94 percent of SCE projects and 72 percent of SDG&E projects. The lengthy contract negotiation process is resulting in contract delays that pose another threat to progress toward RPS goals. A year after their 2005 requests for offers, SCE and SDG&E have yet to file an advice letter based on those solicitations with the CPUC. Table 3 shows the length of time between the IOU requests for offers and the first contracts submitted to the CPUC approval for the 2003, 2004, and 2005 solicitations. In addition, after nearly four years of RPS implementation, there is still no yearly schedule of solicitations.

## Figure 9. Status of Investor-Owned Utility Renewables Contracts




Source: Exeter Associates and Black & Veatch, *Thoughts on the Potential for Renewable Energy Contract Failure*, presentation at the August 22, 2006 Integrated Energy Policy Report Committee workshop, *Midcourse Review of the Renewables Portfolio Standard Process*.

## Table 3. Months from Request for Offers to First Advice Letter Filing

| | 2003 RFOs | 2004 RFOs | 2005 RFOs | 2006 RFOs (expected) |
|---|---|---|---|---|
| **SCE** | 19 | n/a | 12+ | 5 |
| **PG&E** | n/a | 10 | 9 | 5 |
| **SDG&E** | n/a | 16 | 12+ | 5 |

Source: KEMA, Inc. Note: SCE and SDG&E's 2005 solicitations have not yet resulted in an advice letter for contract approval.

In addition, the contracting process itself, from solicitations through contract negotiations, has been identified by developers and developer associations as a major problem with the RPS program. Earlier Energy Commission suggestions of standardizing more contract terms and conditions in order to shorten the negotiation process were met with assurances from the IOUs that each company was moving to its own contractual template and that future procurement cycles would be marked by shorter timeframes. In a survey conducted by an Energy Commission consultant,[74] respondents stated that the terms and conditions of solicitations were onerous, and that many of the contracts being signed were with projects that were unlikely to be developed.

## Repowering Aging Wind Energy Turbines to Increase Electricity Generation

The *2004 Integrated Energy Policy Report Update* identified the need to repower the state's fleet of aging wind turbines, as did the *2005 Integrated Energy Policy Report.* The issue is revisited here because of the lack of progress toward resolving barriers to repowering the state's aging wind energy facilities.

About 1,300 MW of the state's 2,230 MW of wind energy turbines were installed in the 1980s.[75] In 2003, the California Wind Energy Association estimated that about 1,000 MW of aging wind turbines are candidates for repowering.[76] These older turbines are often located in some of the best wind resource areas and are already connected to the transmission grid, although some are located in transmission constrained areas. However, in addition to using older, outdated technology, these turbines are undersized and inefficient compared with current wind turbine technology. With the state behind schedule on achieving 20 percent renewables by 2010, largely due to the need to build transmission to new resource rich areas, these turbines should be replaced promptly, applying the best available science to reduce avian impacts.

In 2003, the CPUC issued a directive requiring "prompt negotiation to resolve what [The Utility Reform Network] characterizes as a stalemate around repower of existing wind facilities" (D. 03-06-071). The *2005 Integrated Energy Policy Report* applauded this directive and recommended the CPUC quickly develop new standardized contracts to overcome impediments to repowering and take advantage of the federal production tax

[74] *Preliminary Stakeholder Evaluation of the California Renewables Portfolio Standard*. CEC-300-2005-011. Prepared by Ryan Wiser, Kevin Porter, and Mark Bolinger. June 2005.

[75] California Energy Commission, October 2001, *Wind Performance Report Summary, 1996-1999,* http://www.energy.ca.gov/wind/documents/1996-1999_wprs_report/index.html, and California Energy Commission, June 2006, *Wind Performance Report Summary 2002-2003,* http://www.energy.ca.gov/pier/final_project_reports/CEC-500-2006-060.html.

[76] Letter from the California Wind Energy Association to California Public Utilities Commission President Michael Peevey regarding California Public Utilities Commission Position on Federal Wind Production Tax Credit Provisions on Repowers, July 21, 2003, as cited in the *2004 Integrated Energy Policy Report Update*.

credit. In addition, the *2005 Integrated Energy Policy Report* raised the issue of provisions in the U.S. Tax Code that impose financial disincentives to repowering.[77] Unfortunately, as shown in Table 4, little progress has occurred. Out of total RPS contracts for between 2,552 and 3,936 MW contracted since 2002 (depending on build-out), only about 4 to 6 percent represents repowered wind.

### Table 4. Repowered Wind Projects Contracted Since 2002.

| Utility | Solicitation | Facility Name | Developer Name | MW | Expected Deliveries (GWh/yr) |
|---|---|---|---|---|---|
| PG&E | 2004 bilateral | Diablo Winds | FPL Energy | 18 | 65 |
| PG&E | 2004 RPS | Buena Vista Energy | Buena Vista | 43 | 108 |
| SCE | 2005 bilateral | CTV Power | CTV Power | 14 | 41.185 |
| SCE | 2005 bilateral | Boxcar II | Windland Inc. | 8 | 20 |
| SCE | 2005 bilateral | Karen Windfarm | Energy Development and Construction Corp. | 11.66 | 35.6 |
| SCE | 2005 bilateral | Coram Energy | Coram Energy Group | 3 | 11.162 |

Source: Energy Commission database, http://www.energy.ca.gov/portfolio/contracts_database.html, updated October 5, 2006.

# Recommendations to Assist in Reaching RPS Goals

Because of the challenges the state faces in meeting the 2010 goal, program improvements are needed. Although a strong consensus among stakeholders exists that the need to build momentum toward 2010 precludes major redesign of the RPS program now, there are several near-term strategies that could be implemented to improve progress toward the 2010 goal. In addition, the state needs to begin evaluating longer-term strategies to put the state on a trajectory to meet the 33 percent by 2020 goal embraced by the Energy Commission, the CPUC, and Governor Schwarzenegger.

## *Near-Term Strategies to Reach 20 Percent by 2010*

### Provide Transmission Access

√ To meet the 20 percent by 2010 RPS goal, the Energy Commission recommends that the CPUC continue to expedite processing of Certificate of Public Convenience and

[77] As stated in the *2005 Integrated Energy Policy Report*, standard offer contracts were instituted by the California Public Utilities Commission to establish prices, terms, and conditions for investor-owned utility purchases from independent generators, including renewable generators, in the early 1980s in response to the federal Public Utility Regulatory Policies Act of 1978.

Necessity applications to assure that critical near-term projects currently in the permitting process are not unnecessarily delayed.

- √ To avoid continuing delays in ensuring additional expansions of renewable transmission in the Tehachapi area to meet both the 20 percent RPS goal by 2020 and the 33 percent RPS goal by 2020, the Energy Commission recommends timely approval of the Tehachapi Plan of Service by the California ISO Board.

- √ To resolve cost allocation issues for renewable transmission, the Energy Commission, the CPUC, other state agencies including the Department of Water Resources, and municipal utilities should all support the California ISO Petition for Declaratory Order from FERC on a third category of transmission projects to facilitate renewable development. In addition, state agencies should work cooperatively to see that the California ISO can move forward with tariff amendments that will allow renewable transmission projects to progress in a timely way.

## Improve Financeability of Supplemental Energy Payments

- √ Because SEP financeability may affect the ability of the state to reach the 20 percent by 2010 goal, the Energy Commission and the CPUC should jointly alter the SEP procedures to reduce the contracting complexity of projects requiring SEPs.

### *Pay Supplemental Energy Payments to Load-Serving Entities*

For projects above the MPR, a utility should be required to bear the risk of SEPs being unavailable. Rather than receive income from the power purchase agreement and a separate income stream from the SEP award, the project owner would receive the full contract amount from the utility. The utility would receive the amount specified in the SEP award, provided funding is available from the Energy Commission.

Under this approach, SEPs would be paid over time to the purchaser of renewable energy (the load-serving entity), rather than to the renewable energy facility. The load-serving entity's renewable electricity contract would be priced at the full as-negotiated contract rate (even if above the applicable MPR), meaning that renewable energy developers would only need to rely upon the credit of the load-serving entity in evaluating the financeability of the project in question. Any above-MPR costs incurred by the load-serving entity would be recovered through SEP payments from the Energy Commission.

Although this approach merely shifts SEP risk from the project developer/owner to the load-serving entity, in doing so it largely resolves SEP financeability concerns, as the load-serving entity would be contractually obligated to make the full payment.

This approach, like the existing SEP structure, does not require that the Energy Commission have the full amount of project-specific SEP funds in house before awarding SEP contracts. Instead, it allows the program to function as originally envisioned – with future Renewable Resource Trust Fund collections dedicated to future SEP payments for projects currently under contract.

An alternative approach that builds upon the current SEP structure would be for the CPUC to simply state by order that any underpayment of SEPs caused by future legislative action would be recoverable in utility rates through an alternative ratemaking mechanism, though applying such an approach to competitive ESPs may be difficult.

### *Move Supplemental Energy Payment Funds to an Escrow Account*

Stakeholders have suggested that Renewable Resource Trust Fund funding for SEP awards be transferred into third-party escrow accounts which would then be paid out to the winning bidders pursuant to the Commission's grant agreement and instructions.

If the purpose of the escrow accounts is to keep funds for SEP awards separate from the Renewable Resource Trust Fund and eliminate the risk that SEP funds will be reappropriated by the Legislature, it is likely that the funds would need to be deposited with a private entity. Arguably, funds deposited with a unit of state government, such as the state treasurer, would still be subject to legislative control. Escrow accounts of this nature would adequately secure SEP funding for financing purposes.

In Massachusetts the MTC Renewable Energy Trust uses such escrow accounts (managed by J.P. Morgan) to hold funds obligated to renewable energy projects as production-based renewable energy certificate purchase awards. MTC uses cash-on-hand (fund collections already in the door) to purchase zero coupon bonds that mature coincident with the trust's obligations to buy RECs from renewable projects; these funds are held in escrow. During the financing process, MTC consents to the developer's assignment of the MTC incentive contract to the new project financier/owner. The project owner then pays the annual fee associated with the escrow account. Projects have found that such escrow accounts are sufficient to ensure financeability, and several projects have successfully completed both debt and equity financings under MTC's program.[78] The principal disadvantage of this escrow-based approach is that the Energy Commission would be required to completely fund the escrow account with funds available up front and would not be able to rely on the promise of future year fund collections.

[78] Typically, the MTC-established escrow account covers 100 percent of MTC's potential obligation or exposure. However, MTC's contract bidding process allows project developers to propose a lower level of escrow funding, and projects proposing less than 100 percent receive a higher evaluation score in that category

New legislation would be needed to implement this change, and a three-way agreement would need to be established between the Energy Commission, the project developer/owner, and the escrow account manager as part of the SEP award process.

Although developers and IOUs requested the Legislature allow SEP awards to be placed in escrow accounts, no legislation on this issue was considered during the 2005–2006 legislative session.

### Enforce Penalties for Non-Compliance

√ The CPUC should continue to make clear to the IOUs its intention to enforce the per-kilowatt-hour penalties for non-compliance with RPS goals, as articulated in CPUC Decision 06-05-039, with penalties applying to unmet renewable needs in 2010. In addition, the CPUC should eliminate the current per-utility cap on those penalties.

Given the large degree of flexibility granted the IOUs in the RPS program, it is essential that penalties for non-compliance be enforced. The California Wind Energy Association raised this issue at the August 22, 2006 workshop, stating:

> …the utilities have asked the PUC for a lot of flexibility in how they go about complying. And they've, to a large extent, received that flexibility. For example, there's almost no standardization of contract terms; little transparency in the least-cost/best-fit process. And wide latitude in the procurement process. So, because they've been given this flexibility, we think it's essential that the PUC hold them accountable for actually meeting the RPS targets on time.[79]

The Energy Commission strongly supports the CPUC's stated commitment to impose penalties for non-compliance with RPS goals. In Decision 03-06-071, issued in 2003,[80] the CPUC identified the penalties for failing to meet RPS goals as five cents for each kilowatt hour short of the RPS target, with an overall annual cap per IOU of $25 million. Decision 06-05-039, issued in 2006, reaffirmed the penalty level and clearly articulated the CPUC's intention to enforce penalties, stating "…we remind IOUs that we are required to enforce our orders if an electrical corporation fails to comply…We have every intention of doing so, and encourage all electrical corporations to undertake all reasonable actions to make the RPS program a success."[81]

[79] Testimony of Nancy Rader, California Wind Energy Association, transcript of the Energy Commission's Integrated Energy Policy Report Committee workshop, Midcourse Review of the Renewables Portfolio Standard Process, August 22, 2006.

[80] California Public Utilities Commission, Decision 03-06-071, June 19, 2003, Order Initiating Implementation of the Senate Bill 1078 Renewable Portfolio Standard Program.

[81] California Public Utilities Commission, Decision 06-05-039, Rulemaking 04-04-026, Opinion Conditionally Approving Procurement Plans for 2006 RPS Solicitations, Addressing TOD Benchmarking Methodology, and Closing Proceeding.

In the 2006 decision, the CPUC also stated, "We will not be sympathetic to granting waivers or reducing penalties due to lack of transmission, for example, without the electrical corporation demonstrating that it took all reasonable action to bring the problem to our attention timely, presented realistic solutions, filed applications timely for necessary projects, and took any and all other actions that could reasonably have been expected to address, if not solve, the problem."[82]

The same penalties were adopted for ESPs in October 2006, in CPUC Decision 06-10-019 in Rulemaking 06-02-012. The CPUC requires that ESPs meet the 20 percent goal by 2010: "The 20% by 2010 goal is clear; ESPs will either take the appropriate steps to meet the goal, or they will explain to us why their potential penalties for failing to meet the goal should be reduced." Yet to date, "as shown in their preliminary renewable portfolio reports, ESPs as a group provide about 0.25 percent of their retail sales from renewable sources," indicating that it may be very difficult for the ESPs to catch up with other load serving entities.[83]

## Increase Transparency

√ The Energy Commission recommends that the CPUC redouble its efforts to make the RPS process more open and transparent, including requiring IOUs to clarify the criteria used in the least-cost, best-fit evaluation of bids and to standardize methodologies used to develop TOD factors.

To address the need for more transparency in the least-cost, best-fit evaluation process, the CPUC held a workshop on December 15, 2006, at which IOUs presented their least-cost, best-fit methodologies to RPS stakeholders. This workshop provided an important opportunity for stakeholders to identify areas where additional clarity is needed and to discuss the need for a standard template to be used by IOUs when describing their methodologies. Hopefully, these discussions will be useful to clarify the process used to select renewable bidders and assist bidders in structuring their bids to better meet the IOUs' energy needs.

In addition, in 2007 the Energy Commission will devote significant priority in its *Integrated Energy Policy Report* to evaluating the least-cost, best-fit methodologies used by the IOUs for all procurement to ensure that those methodologies are consistent with the state's needs for new generation.

As discussed earlier, recent decisions at the CPUC on confidentiality represent an important first step in providing additional transparency in the RPS program. However, in the CPUC's decision on confidentiality,[84] some inconsistency is apparent between the

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[82] Ibid.

[83] California Public Utilities Commission, Decision 06-10-019 in Rulemaking 06-02-012, October 5, 2006.

[84] California Public Utilities Commission Decision 06-06-066, Rulemaking 05-06-040 *Interim Opinion Implementing Senate Bill No. 1488, Relating to Confidentiality of Electric Procurement Data Submitted to the Commission,* June 29, 2006.

decision and an attached matrix that describes confidentiality treatment for classes of information. The matrix does not reflect the language in the decision itself in terms of more limited confidentiality for the RPS and will need to be modified to be consistent with the apparent intent of the decision.

### Incorporate the Risk of Contract Failures and Delays

- √ To address the risk of contract failures and delays, the Energy Commission recommends that utilities procure a contract risk reserve margin of 30 percent or more above the amount needed for them to achieve 20 percent renewables by 2010.

- √ In addition, to assure that renewable development contracts progress rapidly toward completion, the Energy Commission recommends that utilities be required to report on project milestones consistent with those required by the Energy Commission for projects receiving supplemental energy payments. The utilities should provide comprehensive reports on milestone status and progress in the semi-annual compliance reports already required under California Public Utilities Commission Decision 06-05-039.

- √ To assist projects in meeting those milestones, the Energy Commission recommends that the state establish an active monitoring program and hot line similar to the "Green Team" hot line for new power plants that was established during the Energy Crisis. This service would provide information and assistance to help renewable energy projects promptly navigate state and local regulatory requirements.

The *2005 Integrated Energy Policy Report* recommended that the CPUC require a 30 percent contract-risk reserve margin above the IOUs' annual procurement targets to prevent under-procurement. CPUC Decision 06-05-039 is an important first step in addressing this problem and stresses the importance of each IOU continuing to include its own procurement margin of safety. The decision also adopts important reporting requirements to better track the progress of each renewable project in meeting its development and operational milestones. Finally, the decision makes it clear that the utilities will be subject to penalties if they fail to adequately plan for compliance with the state's RPS.

The Energy Commission endorses Decision 06-05-039 and acknowledges that the decision begins to address the underlying concern of contract failure. However, it remains unclear whether the contingency planning currently being undertaken by the three IOUs (as summarized in Decision 06-05-039) will result in the 20–30 percent "margin of safety" identified in the Energy Commission's contractor report on potential contract failure.

Project milestones have been tracked in the past to ensure completion of renewable projects. In the mid 1980s, the CPUC required milestone reporting for qualifying facilities in northern California.[85] To maintain interconnection priority, developers were required to meet a specific milestone schedule that became operative after the developer signed an Interconnection Facilities Agreement. Missing a milestone resulted in a project being moved to the end of the waiting list for transmission connection.

When it was initially established in 1998, the Renewable Energy Program also used milestones to encourage projects to stay on track. In that program, auctions were used to award fixed, generation-based incentives for the development of new renewable generation facilities. Auction winners were eligible to receive incentives for generation for their first five years of operation. After approval of their awards, winners were required to proceed through a series of milestones culminating in coming on line.[86]

A third example of milestones to ensure completion of renewable energy projects is being used in the award of SEPs for above-market RPS contracts.[87] When applying for SEPs, sellers must agree to notify the Energy Commission in writing as soon as possible in the event of potential failure to meet a milestone. These milestones include: demonstration of site control, execution of an engineering, procurement, and Construction contract, execution of an interconnection agreement, receipt of environmental permits, and project on-line date. If a project misses a milestone, the Energy Commission can terminate the project's SEP award. This process will require developers to keep projects on track and results in best use of public funds to incentivize projects that will accomplish state goals on time.

During the 2000–2001 energy crisis, the Governor's "Clean Energy Green Team" operated a hot-line to help new renewable electricity generators achieve project milestones and come on line.[88] The team oversaw local permitting and construction processes for small renewable and peaking plants. Energy Commission staff were assigned to support the green team in their work to coordinate with the 14 California Environmental Protection Agency regional permit assistance centers to provide developers of renewable and emergency power plants with permitting and construction assistance.

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[85] California Public Utilities Commission, Decision 85-01-038, I. 84-04-077, Supplemental opinion adopting interconnection priority procedures for the allocation of transmission capacity among qualifying cogeneration and small power productions facilities. January 16, 1985. See the end of Appendix A for list of milestones.

[86] A detailed description of the process and milestones is provided in the *New Renewable Resources Account Guidebook, Volume 2A, Sixth Edition*, P500-01-014V2A, November 2003 at http://www.energy.ca.gov/renewables/documents/archive/new_renewables/2004-01-23_500-01-014V2A-6th.PDF.

[87] For a list of milestones, see *New Renewable Facilities Program Guidebook*, April 2006, http://www.energy.ca.gov/2006publications/CEC-300-2006-006/CEC-300-2006-006-F.PDF.

[88] Roger Johnson, California Energy Commission, *Permitting Assistance during the 2000-2001 Energy Emergency*. Presentation, August 22, 2006, Integrated Energy Policy Report Committee workshop, Midcourse Review of the Renewables Portfolio Standard. http://www.energy.ca.gov/2007_energypolicy/documents/2006-08-22_workshop/presentations/7-PERMITTING_ASSISTANCE_2001-2002_JOHNSON.PDF.

The Green Team was discontinued after the energy crisis and the regional permit assistance centers disbanded. Currently, the only available assistance is a Web site for developers with a list of needed permits, developer and local agency assistance guides, and an energy-aware planning guide for energy facilities. Although the Web site is useful, no one is available to answer questions.

### Require Bilateral Contracts at or below the Market Price Referent

√ The Energy Commission recommends that the IOUs be required to accept all bilateral RPS offers under the MPR, as long as such an approach does not increase program costs.

√ To contain RPS program costs, IOUs should be given the option of documenting why bilateral offers below the MPR are not selected. When conducting all-source solicitations, the IOUs should document that selected bids are superior to all of the bids received in the most recent RPS solicitation, based on the same gas-price forecast included in the MPR.

California can benefit from experiences of other states and Europe to improve the RPS process. For example, Texas has installed an impressive amount of renewable energy over a short period of time using an RPS and renewable energy certificates. In 2001, less than 1 percent of electricity in Texas was generated by renewable energy.[89] Today, Texas has more installed wind energy generation than California.[90]

The European Union has also made impressive progress in increasing its use of renewable resources, with installed wind energy in the EU–15 countries[91] growing at a rate of 35 percent per year. In 2001, the European Union established a target for renewable resources to provide 21 percent of electricity consumption by 2010, including large hydropower. By 2003, 14 percent of electricity in the expanded community of European countries (EU–25),[92] or almost 400 terawatt-hours, was generated by renewable fuels including large hydropower. About a fourth of that was generated by non-hydropower renewables.

These results have been achieved through feed-in tariffs, green certificates, tendering systems, and tax incentives. The effectiveness of each support method differs by technology and country, with feed-in tariffs being most effective for most technologies

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[89] U.S. Department of Energy, Energy Efficiency and Renewable Energy, *Texas Energy Statistics: Texas Fuels for Electric Power Generation*, http://www.eere.energy.gov/states/state_specific_statistics.cfm/state=TX. Accessed October 6, 2006.

[90] Mark Bruce, *SB 20 and Renewable Energy Development in Texas*, presentation at the August 22, 2006, Integrated Energy Policy Report Committee workshop, Midcourse Review of the Renewables Portfolio Standard.

[91] EU-15 countries: Austria, Belgium, Denmark, Finland, France, Germany, Greece, Ireland, Italy, Luxembourg, Netherlands, Portugal, Spain, Sweden, United Kingdom.

[92] EU-25 countries: Austria, Belgium, Cyprus, Czech Republic, Denmark, Estonia, Finland, France, Germany, Greece, Hungary, Ireland, Italy, Latvia, Lithuania, Luxembourg, Malta, The Netherlands, Poland, Portugal, Slovakia, Slovenia, Spain, Sweden, United Kingdom.

in Germany, Denmark, and Spain, among others.[93] Feed-in tariffs are set at a fixed price, or a fixed premium above spot market prices. Price levels and premiums vary by technology, reflecting variation in technology costs.[94]

Within the current program structure of California's RPS, renewable energy and RECs must be delivered to California to be eligible for the RPS. Because California cannot apply the REC-based approach used in Texas, participants at the August 22, 2006 Integrated Energy Policy Report workshop were asked to comment on whether bilateral contracts could be used to achieve growth in renewable energy development in California similar to the growth that has resulted from European feed-in tariffs. Parties were also asked to comment on whether the CPUC should require IOUs to sign contracts for any renewable energy offered at or below the MPR.

In its written comments, PG&E opposed requiring IOUs to accept bilateral contracts at the MPR because of the potential of overpayment, similar to the situation in the 1980s with qualifying facility standard offer contracts. In addition, PG&E believes this approach does not provide any incentive for technology innovation and does not account for the fact that deliveries must actually meet utility loads.

Further, PG&E and SCE claim that the current RPS process has resulted in contracts below the MPR which in aggregate have saved them "hundreds of millions of dollars"[95] over the life of the contracts compared to the amount that would have been paid if the contracts were priced at the MPR. While the utilities have apparently signed many contracts below the MPR, Energy Commission staff have been unable to verify such savings because of the data opaqueness which continues to plague the solicitation process. Despite the Committee's request at the August 22, 2006 workshop for documentation of these claimed savings, no such information was provided.

Because the CPUC can require acceptance of streamlined bilateral contracts below the MPR within the current structure of the RPS, this contracting method could be implemented quickly, helping the state to achieve both the 20 percent by 2010 goal and the 33 percent by 2020 goal as well.

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[93] Commission of the European Communities, Brussels, 7.12.2005, COM(2005) 627 final, Communication from the Commission, The support of electricity from renewable energy sources, {SEC(2005) 1571}, http://eur-lex.europa.eu/LexUriServ/site/en/com/2005/com2005_0627en01.pdf, pp. 3-4, Annex 1 and Annex 3.

[94] Kevin Porter, *Feed-In Tariffs*, presentation at the August 22, 2006, Integrated Energy Policy Report Committee workshop, Midcourse Review of the Renewable Portfolio Standard. http://www.energy.ca.gov/2007_energypolicy/documents/2006-08-22_workshop/presentations/4-FEED-IN_TARIFFS-K-PORTER.PDF.

[95] Testimony of Roy Kuga, Pacific Gas and Electric Company, and Stuart Hemphill, Southern California Edison Company, transcript of the Energy Commission's Integrated Energy Policy Report Committee workshop, Midcourse Review of the Renewables Portfolio Standard Process, August 22, 2006, pp. 182–183.

## Use Financial Incentives

√ The Energy Commission recommends coordinating with the CPUC to evaluate the potential to provide a higher rate of return for renewable energy facilities that will make them more financially attractive to utilities.

Under Public Utilities Code section 454.3, the CPUC has the authority to approve an increase from one-half of 1 percent to 1 percent in the rate of return otherwise allowed an electrical corporation for its electricity generating plants if they are fueled by renewable energy or meet other environmentally preferred characteristics.

In 2003, the CPUC opened a proceeding (R.03-03-015) to implement this incentive, intending to clarify rules for the incentive up front rather than on a case-by-case basis. IOU interest appeared to be low at the time, so the CPUC closed the proceeding, but left the door open to returning to the topic in the future (D.05-05-027).

In 2006, Senate Bill 1368 (Perata), Chapter 598, Statutes of 2006, was passed which states, "A long-term financial commitment entered into through a contract approved by the commission [CPUC], for electricity generated by a zero- or low-carbon generating resource that is contracted for, on behalf of consumers of this state on a cost-of-service basis, shall be recoverable in rates, in a manner determined by the commission consistent with section 380. The commission may, after a hearing, approve an increase from one-half to 1 percent in the return on investment by the third party entering into the contract with an electrical corporation with respect to investment in zero- or low-carbon generation resources authorized pursuant to this subdivision."

This provision appears to broaden the CPUC's authority to approve an environmentally preferred rate of return to plants beyond those owned by the utilities. However, it is unclear how the provision would be implemented, given that the CPUC does not regulate third party rates of return. The CPUC and the Energy Commission should work together to determine how such authority should be used and whether it could help encourage renewable development that could contribute to the state's RPS goals.

## Use Consistent Natural Gas Price Forecasts

√ The Energy Commission recommends that natural gas price forecasts used in developing the MPR be consistent with those used in other proceedings and that the state should consider moving toward a portfolio-based approach to select an appropriate mix of generation resources.

Natural gas forecasts are used in CPUC proceedings to determine the value of resources in the state's loading order: energy efficiency, demand response, renewable generation, and clean fossil fuel generation. However, the forecasts used are not consistent across all proceedings.

The loading order was adopted in the *2003 Energy Action Plan* prepared by the energy agencies and the Energy Commission's *2003 Integrated Energy Policy Report* made it the foundation for its recommended energy policies. As part of its effort to implement the loading order, the CPUC established renewable energy as the rebuttable presumption for all-source long-term procurement processes. However, the economic value given to the first two preferred loading order resources is determined largely by comparison with the expected cost of a proxy new gas-fired generation plant. This implicitly accepts the existing portfolio of aging gas-fired generation as it is, reinforcing the state's exposure to fuel price volatility as discussed extensively in the *2005 Integrated Energy Policy Report.*

In addition, the methodology used to select the appropriate mix of generation for California's future will have a strong effect on the balance between economic risk and stability that will be borne by the state's ratepayers. Use of the MPR snapshot of then-current natural gas price forecasts as the standard against which the costs of renewable resources are compared does not provide a true valuation of risk. This approach to increasing renewable generation's share of the statewide generation portfolio is at odds with the idea of market risk, which has been a critical part of modern finance theory since the development of the Capital Asset Pricing Model more than 40 years ago.

Ultimately, an integrated portfolio analysis that balances risks associated with conventional and renewable generation choices with best estimates of likely future costs will best serve future electricity needs. It is well known that a diversified pool of stocks, bonds, and other uncorrelated investments can increase risk-adjusted yields. The same is true for a diverse portfolio of electricity generation resources, with efficiency and renewables serving as analogues to fixed income investment.

## Encourage Repowering of Aging Wind Facilities

√ The Energy Commission recommends that the state evaluate possible incentives to encourage repowering of aging wind facilities to increase the amount of renewable generation from these prime sites while reducing the number of bird deaths associated with the operation of wind turbines.

The Energy Commission recommended actions in both the *2004 Integrated Energy Policy Report Update* and the *2005 Integrated Energy Policy Report* intended to help encourage the repowering of wind facilities. However, little progress has been made. Recognizing the importance of the federal production tax credit for wind energy, the provisions in federal law that make it difficult for repowered wind energy to qualify for this federal incentive should be removed. Also, the state should review policies in other countries to encourage repowering of aging wind turbines. Informed by this review, the state should consider enacting a production tax credit or other incentive program to encourage efficient use of the state's wind energy resources.

As part of the planning process to change the location, number, or height of wind turbines, developers need to be aware of recent Federal Aviation Authority and Department of Defense requirements that wind turbines not interfere with air defense radar and determine how best to mitigate the impacts.[96]

This evaluation should be done as part of the 2007 Integrated Energy Policy Report process and include public workshops and dialogue on whether and what type of incentives could encourage more repowering in the state.

## Long-Term Strategies to Reach 33 Percent by 2020

The 33 percent goal has taken on new importance in light of California's aggressive goals for reducing greenhouse gas emissions. In 2005, Governor Schwarzenegger signed Executive Order #S-3-05 which sets the following greenhouse gas reduction goals for California:

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

California's interagency Climate Action Team compiled a list of strategies designed to achieve the first two goals and concluded that achieving the state's renewable energy goals is essential to reaching the goals, second only to reducing emissions from vehicle use.[97] In the Climate Action Team's report, expected reductions of climate change emissions resulting from a 33 percent by 2020 RPS goal totaled 11 million tons $CO_2$ equivalent, compared to reductions of 30 million tons $CO_2$ equivalent expected from vehicle climate change standards.[98]

In addition, two new pieces of legislation signed this year give new weight to the state's renewable energy goals by making renewable energy an essential part of achieving the state's greenhouse gas reduction targets.

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[96] For further information, see https://www.oeaaa.faa.gov/oeaaaEXT/portal.jsp. U.S. Department of Defense, 2006, "Report to the Congressional Defense Committees: The Effect of Windmill Farms on Military Readiness." http://www.defenselink.mil/pubs/pdfs/WindFarmReport.pdf.

[97] Updated numbers from the California Department of Transportation for potential greenhouse gas reductions from smart land use and intelligent transportation systems (shown in Table 6 in Chapter 3) indicate that these strategies are now slightly ahead of renewables in expected emission reductions.

[98] Climate Action Team Report to Governor Schwarzenegger and the Legislature, April 2006, http://www.climatechange.ca.gov/climate_action_team/reports/2006-04-03_FINAL_CAT_REPORT.DOC.

AB 32 requires the reduction of greenhouse gas emissions to 1990 levels in 2020, with the intent to continue reducing emissions beyond 2020.[99] To achieve this goal, each sector subject to AB 32, including the sector responsible for electricity consumed in California, must achieve the maximum technologically feasible and cost-effective reductions in greenhouse gas emissions.

Further, under SB 1368, California will begin requiring utilities to meet a greenhouse gas performance standard in 2007.[100] The bill contains other provisions to encourage utilities to sign long-term cost-of-service contracts for electricity generated by zero- or low-carbon generating resources.[101]

Renewable energy provides a host of benefits to California. Increased use of renewable energy reduces carbon emissions in the electricity sector, which in turn reduces the environmental consequences of electricity generation and offsets the cost of future carbon regulation. These effects are especially salient given the requirements of AB 32 and SB 1368.

Recognizing the risk of future carbon regulations, in December 2004, the CPUC directed the large IOUs to employ a "greenhouse gas adder" when evaluating renewable energy and fossil-energy bids more than five years in duration and in future long-term procurement plans (CPUC Decision 04-12-048). In a subsequent decision in April 2005 (CPUC Decision 05-04-024), the CPUC adopted a $CO_2$ adder for use in resource planning and bid evaluation of $8 per ton of $CO_2$ in 2004, escalating at 5 percent per year. Though renewable energy technologies are diverse and do not have uniform carbon impacts, a common assumption is that renewable sources as a whole are carbon beneficial. Assuming that renewable generation offsets combined cycle natural gas plants with a $CO_2$ emissions rate of 0.43 tons per MWh, an $8 per ton of $CO_2$ adder translates into a $3.2 per MWh benefit of renewable energy.[102]

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[99] Assembly Bill 32 (Nuñez), Chapter 488, Statutes of 2006 defines statewide greenhouse gases as the total annual emissions of greenhouse gases in the state, including all emissions of greenhouse gases from the generation of electricity delivered to and consumed in California, accounting for transmission and distribution line losses, whether the electricity is generated in state or imported.

[100] The California Public Utilities Commission is implementing Senate Bill 1368 (Perata), Chapter 598, Statutes of 2006, in proceeding R.06-04-009. In October 2006, parties filed comments and reply comments on the October 2, 2006 final staff workshop report and proposed methodology for setting and enforcing a performance standard for long-term baseload contracts entered into by investor-owned utilities, energy service providers, and community choice aggregators. The Administrative Law Judge expects to issue a proposed decision in mid-December, with California Public Utilities Commission adoption in January 2007.

[101] Effective for California Public Utilities Commission-regulated utilities by February 1, 2007, and local publicly owned electric utilities by June 30, 2007, Senate Bill 1368 (Perata), Chapter 598, Statutes of 2006 prohibits long-term financial obligations, including ownership and contracts five years or longer, with power plants, including biomass and biogas power plants, that exceed the state's greenhouse gas performance standard.

[102] This assumes a carbon content of pipeline natural gas of 117.080 lbs/million BTU (see: http://www.eia.doe.gov/oiaf/1605/coefficients.html) and a heat rate of 7,347 BTU/kWh (equivalent to the heat rate used to calculate the 2005 market price referent).

However, future carbon regulation could cost more than $8 per ton of $CO_2$. In western utility resource planning documents, for example, there is a great deal of inconsistency in how carbon risk is analyzed, and the presumed levelized cost of carbon reduction ranges from $0 to $58 per ton of $CO_2$, depending on the utility and the resource planning scenario.[103] Incorporating these findings, along with modeling results and experience from emerging carbon markets in Europe and elsewhere, Synapse Energy Economics developed its own forecast of future $CO_2$ costs: (1) low at $8.5 per ton; (2) mid at $19.6 per ton; and (3) high at $30.8 per ton.[104] These forecasts suggest that a $CO_2$ adder higher than $8 per ton may be justified. Applying these forecasted costs to carbon emissions from combined-cycle gas plants yields a benefit of renewable energy of $3.4 per MWh (low), $7.8 per MWh (mid), and $12.3 per MWh (high).

Renewable energy also offers the state important resource diversification benefits beyond the direct benefit of fixed-price electricity. For example, compiling the results of a large number of recent studies, research at Lawrence Berkeley National Laboratory shows that renewable energy will displace gas-fired generation and thereby put downward pressure on natural gas prices. Though the magnitude of this benefit is far from certain, this research indicates that in-state natural gas price reductions that would result from a 20 percent by 2010 renewable target could provide gas savings of three to seven dollars for each MWh of renewable generation.[105]

Renewable energy offers a number of additional benefits as well. For example, a growing number of studies show that renewable energy sources are more labor intensive, and offer greater local economic benefits, than conventional forms of generation.[106] The California Climate Action Team's recent report to the Governor and Legislature appears to confirm this claim, finding that a selection of carbon-reduction strategies (including aggressive renewable energy deployment) could increase employment in California by 83,000 net jobs by 2020.[107]

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[103] Mark Bolinger and Ryan Wiser, 2005, *Balancing Cost and Risk: The Treatment of Renewable Energy in Western Utility Resource Plans*. LBNL-58450. Berkeley, Calif.: Lawrence Berkeley National Laboratory.

[104] Johnson, L. E. Hausman, A. Sommer, B. Beiwald, T. Woold, D. Schlissel, A. Roschelle and D. White. 2006. "Climate Change and Power: Carbon Dioxide Emissions Costs and Electricity Resource Planning." *Synapse Energy Economics*.

[105] Ryan Wiser and Mark Bolinger. 2006. "Can Deployment of Renewable Energy and Energy Efficiency Put Downward Pressure on Natural Gas Prices." Accepted for publication in *Energy Policy*. Page 3. The range in potential benefits reflects uncertainty in the inverse price elasticity of natural gas supply. Also see: Center for Resource Solutions. 2005. "Achieving a 33% Renewable Energy Target." Prepared for the California Public Utilities Commission.

[106] See for example (1) Renewable Energy Policy Project (REPP). 2001. *The Work that Goes into Renewable Energy.* Research Report No. 13. Washington, D.C.: Renewable Energy Policy Project. (Authors: V. Singh and J. Fehrs). (2) Laitner, J. 2006. *An Annotated Review of 30 Studies Describing the Macroeconomic Impacts of State-Level Scenarios Which Promote Energy Efficiency and Renewable Energy Technology Investments.* EPA Office of Atmospheric Programs. (3) Pedden, M. 2006. *Analysis: Economic Impacts of Wind Applications in Rural Communities.* NREL/SR-500-39099. Golden, Colorado: National Renewable Energy Laboratory.

[107] Climate Action Team Report to Governor Schwarzenegger and Legislature. May 2006, http://www.climatechange.ca.gov/climate_action_team/reports/2006-04-03_FINAL_CAT_REPORT.PDF.

## Potential Structural Changes in the Renewable Portfolio Standard

While this update report focuses on near-term strategies needed to reach the 2010 RPS goal, in order to maintain the pace of renewable development in the long-term and reach the 33 percent by 2020 goal, the state needs to evaluate post-2010 structural changes in the RPS that will enable California to reach that higher goal.

Each of the recommendations that follow proposes further analysis before making major changes in the RPS program structure. This analysis will be undertaken by the Energy Commission during the 2007 Integrated Energy Policy Report process.

### *Capture Full Benefits of Renewables in the Market Price Referent*

√ The Energy Commission recommends further analysis of a portfolio-based valuation of renewable energy to fully account for the benefits of renewables.

It is clear that the time-dependent MPR does not capture the full benefits of renewable energy to the state. Indeed, it is these additional benefits that presumably motivated the establishment of the state's RPS.

In addition to displacing natural gas use within California, renewable energy reduces the state's reliance on imported fuels, which often come from regions of the world where conflict and political instability threaten the security of fuel supplies. Increased levels of renewable generation also provide a host of health and economic benefits by reducing the impacts of electricity generation on air and water quality. Also, certain renewable technologies offer unique and currently non-monetized benefits to the state. Biomass power plants, for example, if responsibly managed and operated, can improve forest health, reduce wildfires, avoid waste disposal costs, reduce water pollution from animal and other waste, and limit open-field agricultural burning.[108]

The combined potential benefits of carbon emissions reductions and natural gas price reductions, for example, are shown to raise the value of renewable energy by a minimum of $6.4/MWh, and a maximum of $20.2/MWh, relative to the MPR.

A recent paper from the Lawrence Berkeley National Laboratory reexamines portfolio risk and portfolio construction for 12 western utilities and suggests that due to fuel price volatility and risk of future carbon regulations, utilities should bring renewables into scenario analysis at an earlier stage. The authors also point out that "Resource plans in RPS states . . . should consider evaluating renewable resources as an option above and beyond the level required to satisfy RPS obligations"[109] and that California utilities may

[108] Some studies have sought to quantify these possible benefits. See, for example, Morris, G. 1999. *The Value of the Benefits of U.S. Biomass Power.* NREL/SR-570-27541. Golden, Colorado: National Renewable Energy Laboratory.
[109] Wiser, R. and Bolinger, M., *Balancing Cost and Risk: The Treatment of Renewable Energy in Western Utility Resource Plans.* August, 2005.

achieve a better balance of risk and price by going beyond minimum required levels of renewable electricity. The conclusion is that increased renewable generation will significantly lower risk.

### *Establish Market-Based Mechanisms to Value Renewable Energy Benefits*

√ The Energy Commission recommends further analysis to clarify the relationship between renewable energy, renewable energy certificates, and carbon emissions trading systems currently operating in other states and other countries.

California should draw on lessons learned in other states and countries to inform development of regulations to implement AB 32. In particular, California should study efforts to avoid increasing local impacts on communities already overburdened with environmental pollution, avoid increasing release of criteria and toxic air pollutants, and maximize environmental and economic benefits to California, if possible.

As part of the state's efforts to reduce greenhouse gas emissions to 1990 levels by 2020, AB 32 authorizes the Air Resources Board to develop a market-based compliance mechanism as part of the regulations it must adopt by January 1, 2011. In the course of developing these regulations, one issue that must be addressed is the relationship between renewable energy and a future market-based greenhouse gas emission reduction mechanism.

Current and forthcoming market-based efforts to reduce carbon emissions range widely in their treatment of renewable energy. In the United States, the regional GHG reduction initiative (RGGI) by New England states aims to reduce $CO_2$ emissions from electricity and thermal output through a market-based $CO_2$ emission trading system. RGGI plans to begin the carbon emissions trading system in 2009. RGGI has published a model rule that allows participating states to set aside RECs from the voluntary renewables market. This set aside would reduce the amount of $CO_2$ allowances available for purchase or trading for a specified control period (usually a year).[110] RECs used to meet a state RPS program are excluded.[111] The model rule recommends allocating at least 25 percent of $CO_2$ allowances to a consumer benefit or strategic energy purpose fund. This fund will sell or distribute allowances and use the proceeds to support energy efficiency, renewable energy, and related public benefits.[112] California plans to link its market-based GHG emission reduction strategy to RGGI (Executive Order S-20-06, October 18, 2006).

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[110] http://www.rggi.org/docs/model_rule_8_15_06.pdf.

[111] On this point, the model rule states (August 15, 2006, p. 20: "The renewable energy generation or renewable energy attribute credits related to such purchases may not be used by the generator or purchaser to meet any regulatory mandate, such as a renewable portfolio standard." http://www.rggi.org/docs/model_rule_8_15_06.pdf.

[112] RGGI Model Rule (August 15, 2006, p. 10), http://www.rggi.org/docs/model_rule_8_15_06.pdf.

Another approach that incorporates carbon benefits with RECs in the voluntary market is Green-e certified unbundled RECs established and administered by the Center for Resource Solutions. Significantly, to be Green-e certified, the environmental benefits, such as carbon reductions, must remain bundled with the REC; if not, the REC is retired.

In Europe, renewable energy is not included in the mandatory carbon trading regime. Instead, the European Union has established a target of renewable resources providing 21 percent of electricity consumption by 2010, including large hydropower.[113] In a number of European countries, unbundled RECs are used to meet renewable energy targets. However, carbon emission reductions from the RECs are not eligible for trading in the greenhouse gas emissions market.

### CARBON EMISSION TRADING SYSTEMS

On October 18, 2006, the Governor issued Executive Order S-20-06, ordering state agencies to develop market-based compliance mechanisms for greenhouse gas reduction, consistent with AB 32 on an expeditious schedule, concurrent with regulatory measures. The Executive Order directs the Secretary for Environmental Protection to create a Market Advisory Committee of national and international experts to make recommendations to the State Air Resources Board on the design of a market-based compliance program. The Order also included the following direction to state agencies:

> The State Air Resources Board shall collaborate with the Secretary for Environmental Protection and the Climate Action Team to develop a comprehensive market-based compliance program with the goal of creating a program that permits trading with the European Union, the Regional Greenhouse Gas Initiative and other jurisdictions. The State Air Resources Board shall consider the recommendations of the Market Advisory Committee in the development of the market-based compliance program;
>
> The Secretary for Environmental Protection shall coordinate with the Climate Action Team to develop a plan by June 1, 2008, which is based on input from the Economic and Technology Advancement Advisory Committee, that will incentivize investment and compliance, enhance research, and develop and demonstrate greenhouse gas emission reduction technologies through a variety of options including, but not limited to: research tax credits, monetary and non-monetary incentives, public/private partnerships, investment tax credits, and accelerated depreciation.

[113] Commission of the European Communities, Brussels, 7.12.2005, COM(2005) 627 final, Communication from the Commission, The support of electricity from renewable energy sources, {SEC(2005) 1571}, http://eur-lex.europa.eu/LexUriServ/site/en/com/2005/com2005_0627en01.pdf.

While AB 32 authorizes the Air Resources Board to develop market-based compliance mechanisms, it requires the board to take steps to reduce negative local impacts and maximize benefits for California:

> Prior to the inclusion of any market-based compliance mechanism in the regulations, to the extent feasible and in furtherance of achieving the statewide greenhouse gas emissions limit, the state board shall do all of the following:
>
> (1) Consider the potential for direct, indirect, and cumulative emission impacts from these mechanisms, including localized impacts in communities that are already adversely impacted by air pollution.
>
> (2) Design any market-based compliance mechanism to prevent any increase in the emissions of toxic air contaminants or criteria air pollutants.
>
> (3) Maximize additional environmental and economic benefits for California, as appropriate.

As the state moves forward to implement AB 32 and Executive Order S-20-06, California should look carefully at whether to allow the IOUs to meet post–2010 RPS requirements with unbundled RECs.

### Renewable Energy Certificates

The Western Renewable Energy Generation Information System (WREGIS) also requires environmental benefits, such as carbon reductions, to remain bundled with the REC. In addition, to meet the California RPS, both the energy and the RECs from RPS-certified renewable energy power plants are required. As noted in a CPUC report on RECs, however, the CPUC currently allows some limited swapping of renewable and non-renewable electricity within California:

> California's existing compliance framework allows for the implicit use of unbundled RECs. D.05-07-039 changed the delivery requirements such that the renewable energy procured pursuant to the RPS need not be delivered into the service territory of the purchasing utility, but must only be delivered into the California ISO [California Independent System Operator] control area. Regardless of whether the purchasing load-serving entity [load serving entity] arranges for delivery of the energy into its service territory or remarkets the energy, it receives credit toward its RPS obligations. Remarketing of the renewable energy is analogous to an unbundled REC transaction since claim over the attributes is dissociated from the ultimate disposition of the energy.[114]

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[114] California Public Utilities Commission, *Renewable Energy Certificates and the California Renewables Portfolio Standard Program*, staff white paper, Division of Strategic Planning, April 20, 2006, http://www.cpuc.ca.gov/PUBLISHED/REPORT/55606.htm.

Unbundled RECs would spread renewable energy used to meet California's post-2010 RPS across the Western states, including renewable energy that is not transmitted to California. Unbundled RECs could reduce the transmission needed to meet post-2010 RPS requirements. Because of presumed lower development costs outside California, it is widely believed that unbundled RECs would bring welcome (from a ratepayer's perspective) downward pressure on the price of renewable generation inside California.

However, there are significant drawbacks to the use of unbundled RECs. Actual electricity demand would be met with electricity generated most likely from natural gas paired with an unbundled REC. This would not reduce the state's over-reliance on natural gas-fired generation or reduce the state's exposure to volatility of natural gas prices. It would not contribute to local efforts to reduce air quality problems, address environmental justice concerns, or necessarily produce in-state tax and employment benefits.

### *Evaluate Production Incentives to Support the 33 Percent Goal*

√ The Energy Commission recommends that the Legislature consider whether to authorize a system benefit charge for renewable energy for the 2011–2020 timeframe or to adopt a RECs model or a renewables feed-in tariff.

Collection of public goods charge funds for the Energy Commission's Renewable Energy Program, including SEPs, is authorized through January 1, 2012.[115] Depending on the portion of contracted projects that come on line, the price of natural gas, and the bid price of RPS projects, SEP funds may be exhausted in support of meeting 20 percent by 2010. However, the state's renewable and greenhouse gas reduction goals extend beyond 2020, and it is unclear what type of financial support, if any, will be available to help the state meet those goals.

The number of contracts signed at or below the MPR indicates that many renewable energy projects are competitive with natural gas projects under current natural gas prices, steel prices, and availability of the federal production tax credit. However, because these conditions fluctuate over time, renewable energy may need support during the lean times to continue investing in development of renewable energy projects, continue bringing innovative renewable energy technologies to market, and further reduce the cost of renewable generation over time.

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[115] As provided in Assembly Bill 995 (Wright), Chapter 1051, Statutes of 2002, and Senate Bill 1194 (Sher), Chapter 1050, Statutes of 2002, enacted on September 30, 2000, ratepayers receiving electricity or natural gas from California Public Utilities Commission-regulated utilities pay a non-bypassable system benefit charge established under Assembly Bill 1890 (Brulte), Chapter 854, Statutes of 1996, in September 1996 and distributed pursuant to Senate Bill 90 (Sher), Chapter 905, Statutes of 1997, starting in January 1998 and continuing through 2011.

The RPS is economically driven, with the MPR closely tied to the current price forecast of natural gas. If natural gas price forecasts drop, renewables could appear more expensive than gas-generated electricity. This could result in a lull in renewables development, as happened in the 1990s when high oil prices forecasted in the 1980s failed to materialize. Similarly, the solar water heating boom of the early 1980s was fueled by high energy prices and correspondingly high subsidies through tax benefits. When energy price forecasts moved lower in the late 1980s and the tax benefits ended, the industry crashed. This kind of boom and bust cycle makes it difficult to develop a mature and stable renewable industry.

After electricity, natural gas is the most volatile energy commodity.[116] Some private reports predict lower prices than do most of the publicly available estimates. In the short term, falling gas prices would likely require much higher levels of SEPs, or a different financial mechanism, to fund "above market" costs of renewable energy. Development of a carbon emissions market may provide some additional assistance for renewable development, but renewable energy generation may need additional public or market resources to continue to develop the industry.

In written comments submitted after the August 22, 2006 Integrated Energy Policy Report workshop, SCE stated: "Most parties at the workshop did not support the use of feed-in tariffs. The discussion seemed to indicate that feed-in tariffs would add complexity, rather than streamline the process. The main barrier to renewable development is transmission, which feed-in tariffs do nothing to address…This proposal could sacrifice the quality of bidders for quantity. As a result, project failures would likely increase, and in the long-run, the IOUs would be no closer to meeting RPS goals."[117]

In contrast, FPL Energy strongly supported feed-in tariffs. FPL Energy is one of the largest developers of renewable energy in the United States. It is part of FPL Group, which includes Florida Power and Light Company, a utility serving about half of Florida (8 million people). FPL Energy owns or operates 700 MW of wind and 310 MW of solar thermal generation in California. Other than its Montezuma wind project in Solano County, which was selected by PG&E in its 2005 RPS solicitation, FPL Energy has been largely absent from developing new renewable energy for the California RPS and has focused its development efforts on other states, including developing more than 1,000 MW of wind energy in Texas.

[116] Energy Risk, *Energy hedge fund bulls still running despite MotherRock collapse,* at http://www.energyrisk.com/public/showPage.html?page=343823.

[117] Southern California Edison, written comments, Integrated Energy Policy Report Committee workshop, Midcourse Review of the Renewable Portfolio Standard, August 22, 2006. http://www.energy.ca.gov/2007_energypolicy/documents/2006-08-22_workshop/comments/SOUTH_CALIFORNIA_EDISON.PDF.

In its comments, FPL Energy stated that it supports using the MPR as a set price for a "feed-in" renewable tariff for bilateral contracts, "as long as it is known prior to the bid and reflects a reasonable forecast of long-term price of energy and capacity." FPL Energy considers the development and financing of energy projects in California to be riskier than in other states, due to the current regulatory structure for the California RPS and the absence of a capacity market, and believes bilateral contracts at a known "feed-in" tariff could help address this problem: "In the near term, [FPL Energy] believes that bilateral contracts are the appropriate mechanism to create the incentive for new renewable energy facility investment in California."[118]

### *Evaluate Potential Structural Changes to Supplemental Energy Payment Process*

√ The Energy Commission recommends further analysis of other potential changes outlined below to the structure of the RPS Program for the 2010–2020 timeframe to ensure that the state reaches the 33 percent by 2020 renewable energy goal.

The *2005 Integrated Energy Policy Report* discussed problems with and alternatives to the MPR/SEP structure that would increase transparency and simplify administration of the RPS program. The structural problems are revisited in this report, adding the issue of financeability to exploration of alternatives to the MPR/SEP.[119] To avoid delay in achieving 20 percent by 2010, the following potential structural changes are intended to apply after 2010. With 2010 only three years away, however, discussion and analysis must begin now.

Potential changes include:

- Pre-paying a secured lump sum to projects.
- Eliminating SEPs while maintaining deliverability requirement.

[118] FPL Energy owns or operates 700 MW of wind and 310 MW of solar thermal generation in California. Other than its Montezuma wind project in Solano County, which was selected in the 2005 Pacific Gas and Electric Company Renewable Portfolio Standard Request for Offers solicitation, it has been largely absent from developing new renewable energy for the California Renewable Portfolio Standard. In contrast, it has developed more than 1,000 megawatts of wind energy for the Texas Renewable Portfolio Standard. Presentation by Mark Bruce at the August 22, 2006, Integrated Energy Policy Report Committee workshop, Midcourse Review of the Renewables Portfolio Standard. And, FPLE, "Letter to Commissioner Geesman on RPS Midcourse Correction 8-22-06 Workshop." http://www.energy.ca.gov/2007_energypolicy/documents/2006-08-22_workshop/comments/ALEX_NAVERKOVEC.PDF.

[119] For a discussion of concerns with the market price referent/supplemental energy payment structure of the RPS, see California Energy Commission, June 2005, *Preliminary Stakeholder Evaluation of the California Renewables Portfolio Standard*, consultant report. Prepared by Ryan Wiser, Kevin Porter, and Mark Bolinger. http://www.energy.ca.gov/2005publications/CEC-300-2005-011/CEC-300-2005-011.PDF. For a critique of the market price referent/supplemental energy payment structure from the perspective of energy service providers and community choice aggregators, see the written comments provided by the Alliance for Retail Energy Markets for the August 22, 2006, Integrated Energy Policy Report workshop.

- Eliminating SEPs and meeting California's RPS with unbundled renewable energy certificates.
- Moving SEP administration to load-serving entities.
- Paying SEPs to ratepayers and passing the full cost of RPS contracts through in rates.
- Awarding SEPs through reverse auctions.

### PRE-PAY SECURED LUMP SUM TO PROJECTS

The State of California does not have the authority to provide advanced payment for services, except under specific statutory exemptions.[120] However, as of October 2006, three state clean energy funds—in Pennsylvania, Illinois, and Oregon—have successfully offered some variation of a secured pre-payment to wind projects that have subsequently been financed and built.[121] Such an approach could avoid the problem of SEP financeability.

The Energy Commission could award SEPs as a pre-paid production incentive directly to the project at the start of commercial operations, with a requirement—secured by a letter of credit, escrow account, or some other means—that the project repay all SEPs that are not earned as required via actual production over time.

In addition to decreasing the notional dollar amount of the SEP obligation (due to the time value of money and discounting) *and* eliminating future funding risk[122]—both of which are also achieved to some degree by the escrow approach discussed above—this "secured pre-payment" approach may also better match most renewable projects' need for up-front capital (especially if the funds are secured by a letter of credit, as opposed to

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[120] The Commission has no authority under the Warren-Alquist Act or the statutes governing the Renewable Energy Program to make advance payment. As a general rule, state agencies are precluded from making advance payment. This is to avoid paying for something (goods, services, etc) that may not be delivered, leaving the state with little recourse to do anything about it, particularly in cases of bankruptcy where creditors must battle it out with each other for a limited share of the bankrupt's assets. The state legislature, however, has carved out several exceptions for certain type of entities, mostly government entities. Specifically, a state agency may make advance payment to another state agency pursuant to Gov. Code 11256 and to a federal agency pursuant to Gov. Code 12425. Approval by the Department of General Services is required in both cases. In addition, a state agency may make advance payments to a community-based private non-profit agency with which it has contracted under federal and state law for the delivery of services pursuant to Gov. Code 11019. Certain state agencies may also make advance to counties for certain county services pursuant to Gov. Code 11019.5. The payment of supplemental energy payments does not fall within any of these specific statutory exemptions.

[121] For more information on the structure of these pre-payments, see section 6.1.3 of http://eetd.lbl.gov/ea/ems/reports/61076.pdf.

[122] Note that there would be some funding risk that remains between the date of supplemental energy payment award and the time at which the lump-sum pre-payment is made (i.e., upon commercial operation). If this risk is viewed as problematic, the lump-sum payment could be made at the time of supplemental energy payment award, and if properly secured, would have to be fully returned to the Energy Commission were the project not able to achieve commercial operations. Security would likely need to be provided in the form of an escrow account (not a letter of credit), however, because if the payment was considered a low-interest loan (much more likely if a letter of credit was used, rather than an escrow account), it would negatively influence the value of the federal production tax credit.

an escrow account, and can therefore be used by the project upon receipt). In other words, it provides the project with many of the same benefits as a grant, without the accompanying risk of non-performance and potentially negative interaction with the federal production tax credit.[123]

The principal disadvantage of this approach, as with the escrow approach, is that the Energy Commission must have the requisite amount of funds available at the time the project achieves commercial operations. Given the small percentage of RPS contracts that have come on line to date, it may be some time before this becomes a problem.

### ELIMINATE SUPPLEMENTAL ENERGY PAYMENTS AND MAINTAINING DELIVERABILITY REQUIREMENT

The state could consider reverting to a more standard RPS, in which load-serving entities are obligated to purchase renewable energy and recover the prudent cost of those contracts in rates, while eliminating SEPs. This option would retain the bundled REC/electricity contract requirement of the state's RPS. In this case, the projects will be financed solely based on the revenue streams from the load-serving entity, not the state. Under the current MPR/SEP structure, many projects do not require SEPs, and when they do, SEPs provide only a minor portion of the project's total revenue stream. However, that minor portion, if financeable, could tip the balance of whether a project is developed or not.

Abolishing the MPR/SEP structure may have other ancillary benefits as well.[124] It would simplify the administration of the RPS; better match the needs of competitive energy service providers; more easily allow the development of renewable energy credit markets; and potentially reduce the cost of achieving the state's renewable energy targets.

The primary advantage of the current MPR/SEP structure is that it effectively establishes a cap on overall program costs. Cost control may also be achieved through other means, however, as experience in other states shows. In fact, one option would be to eliminate SEP payments, but to retain the MPR. Under this scenario, the MPR is simply used to determine the "above-market" cost of any particular renewable energy contract, with contracts priced at above the MPR approved by the CPUC as long as the load-serving entity (or all load-serving entities in aggregate) is within its pre-determined RPS cost cap. The CPUC would retain contract approval responsibilities, so governmental

[123] If structured properly – for example, if awarded only after the project has achieved commercial operations, so as not to be considered "subsidized financing" – a secured supplemental energy payment pre-payment will likely not trigger the production tax credit's anti-double-dipping provisions. For more information on Internal Revenue Service treatment of similar funding mechanisms in other states, see section 6.1.3 of http://eetd.lbl.gov/ea/ems/reports/61076.pdf.

[124] California Energy Commission, June 2005, "Preliminary Stakeholder Evaluation of the California Renewables Portfolio Standard," consultant report, pp. 18, 55-57, http://www.energy.ca.gov/2005publications.

oversight would remain. Utility incentives could be focused on the size of the difference between the MPR and RPS costs.

The primary challenge with eliminating SEPs is that it fundamentally alters the structure of the state's RPS. Developing regulatory guidelines for such a program will take time. To avoid delays in achieving the state's renewable energy targets, such discussion should probably focus on post–2010 only.

### ELIMINATE SUPPLEMENTAL ENERGY PAYMENTS AND MEETING CALIFORNIA'S RPS WITH UNBUNDLED RENEWABLE ENERGY CERTIFICATES

RECs are used to account for and verify compliance with RPS policies in the majority of states with RPS programs. These RECs are typically allowed by state regulatory agencies to be unbundled from their underlying electricity source and traded separately. States differ markedly in the degree to which market-based RECs unbundling takes place and the degree to which RECs are sold in short-term versus long-term markets. These choices can affect whether the revenue stream from RECs can help new renewable projects obtain financing, depending on the project and the market structure.

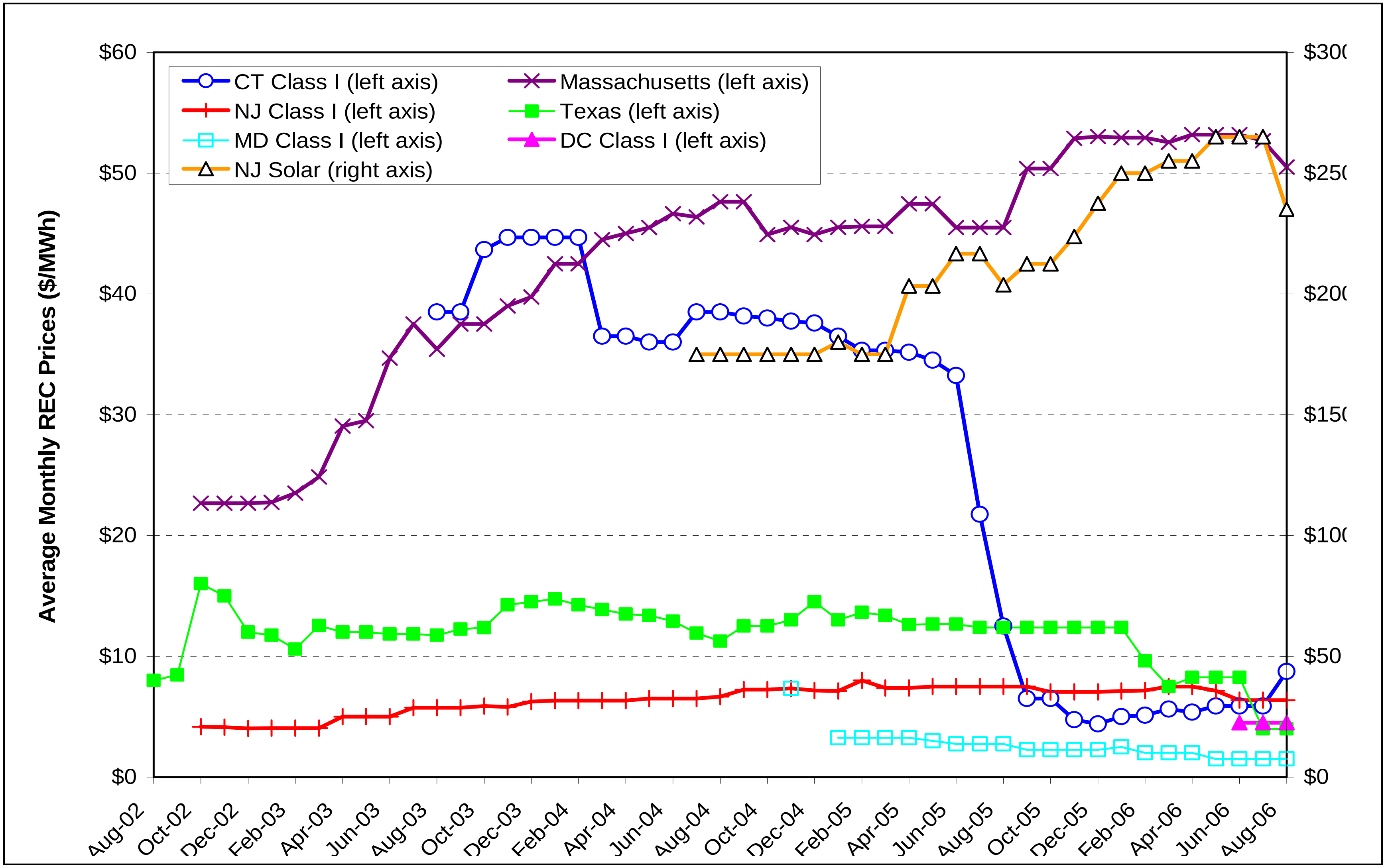
RECs have been employed in Nevada, New Mexico, Wisconsin, Texas, and Arizona for some time now, but the utilities in those states have typically sought to purchase renewable electricity under long-term contract. As a result, REC trades represent a relatively small segment of the overall market. Even when trades have occurred, they have typically been among regulated electric utilities, and trading prices are not always made public. In other states, RPS policies have been established so recently that little history of RECs prices exists.

In some states, trade in unbundled RECs is liquid and transparent enough for market price data to be available. These states typically have retail electric competition and liquid wholesale electricity markets. Evolution Markets has reported monthly REC prices for these markets since late 2002 (or since each individual market became liquid enough to report price data).[125]

Figure 10 on the following page shows monthly data on the average price of RECs in six different states and seven total markets (two New Jersey markets are included: Class I and Solar).

[125] Several limitations to these data deserve note: (1) though price data are available, they are limited to trades managed by Evolution Markets, and these markets are often not particularly liquid; and (2) averaging of price data often requires that one average trades representing renewable energy certificates of various vintages, or using bid and offer price data where actual trade price data were unavailable.

**Figure 10. Monthly Average Renewable Energy Certificate Prices**




Source: Evolution Markets, Inc. Data Bank (http://www.evomarkets.com/index.html), compiled by Lawrence Berkeley National Laboratory. October 2006.

Figure 10 demonstrates that REC prices experience considerable variation among markets and even within a single market over time. REC price differences across markets reflect different RPS designs:

- Resource, vintage, and geographic eligibility rules.
- The level of the RPS compliance target.
- The cost and availability of renewable generation in the region.

The level and design of any cost cap, and so forth. Table 5 summarizes the mean, standard deviation, and coefficient of variation of average monthly REC prices in each of these seven markets.[126]

## Table 5. Comparison of Monthly Average Renewable Energy Certificate Prices[127]

| | CT Class I | Massachusetts | NJ Class I | NJ Solar | Texas | MD Class I | DC Class I |
|---|---|---|---|---|---|---|---|
| **Mean** | 26.67 | 42.52 | 6.37 | 213.46 | 11.84 | 2.62 | 4.50 |
| **Standard Deviation** | 15.72 | 4.89 | 0.60 | 33.77 | 2.60 | 1.24 | 0.00 |
| **Coefficient of Variation** | 0.59 | 0.11 | 0.09 | 0.16 | 0.22 | 0.47 | 0.00 |

Source: Evolution Markets, Inc. Data Bank (http://www.evomarkets.com/index.html), compiled by Lawrence Berkeley National Laboratory, October 2006.

Variations in REC prices within a market, over time, reflect several influences, such as: changes in RPS rules or expectations of those rules; the actual and/or expected speed of renewable energy development relative to the RPS targets; and the degree of competition for renewable energy from other states or from the voluntary green power market.

For example, the precipitous drop in REC prices in Connecticut in 2005 is due to a decision by the Connecticut Department of Public Utility Control that found that existing Maine biomass plants that are retrofitted with more stringent emission controls qualify as Class I renewable resources, thereby flooding the market with RECs that were previously thought ineligible for the state's RPS.

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[126] Not included here are price data for renewable energy certificates product types that are not intended to support new renewable generation. For example, CT Class II, DC Tier II, NJ Class II, MD Tier II, and Maine renewable energy certificates all allow a considerable amount of existing renewable generation to qualify, ensuring that these renewable energy certificates are unlikely to trade for values substantially above zero. Those data are therefore not included in Figure 10.

[127] The period of time for which renewable energy certificate prices are available for each state is as follows: CT Class I (Aug 03 - Aug 06), Massachusetts (Oct 02 - Aug 06), NJ Class I (Oct 02 - Aug 06), NJ Solar (Jul 04 - Aug 06), TX (Aug 02 - Aug 06), MD Class I (Jan 05 - Aug 06), DC Class 1 (Jul 06 - Aug 06).

Prices in Texas have also experienced some fluctuation. For the first several years of the Texas RPS, RPS-eligible supply exceeded RPS demand; however, voluntary purchases from green power customers supplemented demand for renewable energy and allowed RECs to trade for above $10 per MWh. More recently, a new influx of wind capacity additions in 2005 and 2006 has led to a drop in REC prices to about $5 per MWh. REC prices in other markets, including Massachusetts and New Jersey (Solar), have trended upward for several years, as it has become clear that RPS-driven demand either does or is likely to exceed eligible renewable energy supply. REC prices in Massachusetts are now established in large measure by the REC price cap in that market, also known as an alternative compliance mechanism, as established by the state government.[128]

Questions have arisen over the degree to which unbundled RECs might provide financeable revenue streams for renewable energy projects. Experience in other states is somewhat mixed. In many still-regulated markets, unbundled RECs are allowed, but sales of RECs in short-term markets have not been the principle form of compliance. In these states, which include Nevada, New Mexico, Arizona, and Wisconsin, electric utilities have typically signed long-term contracts for bundled electricity/RECs transactions, with unbundled RECs used in more limited circumstances. In these instances, renewable energy projects have had little difficulty obtaining financing.

In Texas, many renewable energy projects have similarly sold their electricity and RECs in a bundled fashion, allowing the project to obtain standard finance, with the purchaser then sometimes selling unbundled RECs to alternative suppliers that do not want to take the commodity risk of purchasing renewable electricity. A growing number of renewable energy developers in Texas, however, are developing their projects as quasi-merchant facilities, selling their electrical output and RECs separately. These projects are relying on commodity electricity sales and (often) separate RECs transactions to earn a profit, though in many instances commodity hedges or medium-term REC contracts are used to limit risk exposure. Similar merchant or quasi-merchant renewable facilities have developed in New England and the Mid-Atlantic markets, though at least in New England, merchant renewable energy development has not kept pace with RPS-driven renewable energy demand, and shortages of renewable energy have therefore developed.

Overall, it appears as if some of the most successful RPS markets are those in which merchant renewable energy projects are an option, but not a requirement of the market

[128] Rick Counihan, Alliance for Retail Energy Markets, written comments for August 22, 2006, Integrated Energy Policy Report Committee workshop, Midcourse Review of the Renewables Portfolio Standard: "Six states with RPS policies currently employ Alternative Compliance Payments (ACPs) as a cost mitigation measure. Under this approach, load-serving entities can pay an ACP in lieu of purchasing a REC when the cost of a compliance renewable energy certificate exceeds a pre-specified level (for example, $50/MWh). In most cases, the ACPs are paid into a fund which is used to support new renewable generation. This still puts the cost of RPS into the rates of the load-serving entity but effectively puts an upper limit on the amount they would have to pay for wholesale renewable power."

structure. Merchant renewable development is most likely to succeed where a deep spot market for power exists (New England, Texas, PJM, and New York), where renewable projects are reasonably economic even without the REC price stream (Texas), or where REC prices are high enough that their long-term value is of less concern (Massachusetts). The most successful RPS markets appear to be those in which RECs are allowed, but are not necessarily always sold separately in short-term markets.

California's RPS already allows a certain amount of delivery flexibility which is an important first step in the direction of RECs unbundling. SB 107 defines a renewable energy credit as "a certificate of proof, issued through the accounting system established by the Energy Commission …, that one unit of electricity was generated and delivered by an eligible renewable energy resource." SB 107 also authorizes the CPUC to allow load-serving entities to use unbundled RECs subject to specific delivery requirements, all of which are to in-state entities. Load-serving entities can swap renewable energy generated in one part of the state for non-renewable energy plus non-tradeable RECs from another part of the state. [129]

A legislative change would be needed if the state wanted to remove the deliverability requirement and allow the use of unbundled REC for renewable electricity not delivered to California. The environmental and economic impacts of such an expanded unbundled REC market should be carefully reviewed if this change is pursued.

### MOVE SUPPLEMENTAL ENERGY PAYMENT ADMINISTRATION TO LOAD-SERVING ENTITIES

Under this approach, the basic SEP mechanism is retained, but funds for SEPs are not transferred to the state. Instead, SEPs are collected and retained by load-serving entities in balancing accounts or through other mechanisms. SEPs would be paid to renewable energy projects in the same manner as currently administered by the Energy Commission, but payment would be made by the load-serving entity. SEPs could be managed by only the large IOUs in the state, but those IOUs would then presumably have an obligation to also pay SEPs to eligible renewable energy projects that have contracts with competitive retail electricity service providers.

Oversight of SEP funds and SEP payments could be provided by the Energy Commission and/or the CPUC, to provide safeguards to IOU administration. (If other ESPs—beyond the IOUs—were also administering SEP funds, then the oversight responsibilities of the Energy Commission and/or CPUC would increase dramatically.)

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[129] California Public Utilities Commission, *Renewable Energy Certificates and the California Renewables Portfolio Standard Program*, staff white paper, Division of Strategic Planning, April 20, 2006 http://www.cpuc.ca.gov/PUBLISHED/REPORT/55606.htm.

The administration of renewable energy funds by electric utilities has been used in several other states, so this option is not altogether new. Because the SEP funds in this case would be paid by the large IOUs, and would not flow through a state account or require state appropriation, it would reduce the risk of nonpayment.

On the negative side, governmental oversight of SEP funds may diminish to some degree. In addition, there is potential for conflict of interest if an IOU is building and financing a plant itself. It is also not clear what advantages this mechanism possesses over the option of simply eliminating the SEP/MPR structure altogether, or of the other modifications suggested in this section.

Because state law requires the CPUC-regulated utilities to collect system benefit charges and remit a specified portion of those funds to the Renewable Resource Trust Fund, this option would require a change in legislation.

### Pay Supplemental Energy Payments to Ratepayers, Passing Full Cost of Renewable Portfolio Standard Contracts in Rates

Another option would be to pass through the full cost of RPS contracts in rates paid by ratepayers.

The amount contributed by ratepayers could be returned as a credit to the electricity bill at the end of each year. The amount to be paid each ratepayer should be proportional to the impact of the above-MPR contracts on the ratepayer's bill, to the extent funds are available.

Alternately, the system benefit charge for the RPS could simply be returned to the ratepayers in the amount paid, the MPR discontinued, and the full cost of RPS contracts would be paid by the ratepayer, subject to contract approval by the CPUC. In addition to addressing the financeability problem, this option would also increase transparency and simplify administration of the RPS. It would also decouple renewable energy contracts from natural gas prices.

Because the current RPS requires SEPs to be paid to eligible facilities, either version of this option would require new legislation to implement.

### Use Reverse Auction to Allocate Supplemental Energy Payments

Prior to the RPS, a different structure was used to provide production incentives for new renewable energy, with some success. The Energy Commission held auctions from 1998 to 2001 to award production incentives payable for the first five years of project operation.

Auction winners received a notice of project award adopted at an Energy Commission business meeting in a similar procedure to the issuance of funding confirmation letters for SEPs. Funding Award Agreements for auction winners were not approved by the Energy Commission until after the projects had completed any required environmental review. Then, as today, there was no guarantee that an award would be paid if funds were not available, with the awards therefore referred to as conditional.[130]

Under the auction process, developers bid the incentive level and award amount they needed to develop and operate a proposed project. The bid could be submitted whether the developer had a power purchase contract with a utility or not. Contracts could be signed without the use of a market price referent to determine the maximum amount to be paid directly by the investor-owned utility.

Because the risk of Legislative removal of SEP funds is borne by the developer, lenders may view auction awards as not financeable. It is not clear whether the SEP awards from the reverse auctions held before the RPS were instrumental in helping projects get financing. However, the fact that nearly 500 MW of new renewable power was brought on line with support from the auction awards suggests that the earlier program was not hampered by a negative impact of the contracting award structure on financeability.

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[130] See *New Renewable Resources Account Guidebook Volume 2B*, p. 13, http://www.energy.ca.gov/renewables/documents/archive/new_renewables/2004-01-23_500-01-014V2B-5th.PDF.

# CHAPTER 3: THE RELATIONSHIP BETWEEN ENERGY AND LAND USE

## Introduction

Experts expect California's population to grow by 20 million people between 2000 and 2050. Such growth will severely tax already constrained energy resources and the associated infrastructure and challenge the state's ability to provide the energy that new communities, homes, schools, industry, and other workplaces will require. This rapidly advancing scenario shines a spotlight on a relationship that until now has received little attention: the profound impact of land use decisions on every aspect of energy and how those choices, in turn, affect California's ability to achieve its statewide energy goals and reverse the tide of global climate change.

In August 2006, the California Energy Commission (Energy Commission) issued a scoping order for the *2007 Integrated Energy Policy Report* directing staff, as part of the *2006 Integrated Energy Policy Report Update*, to examine existing studies and policies related to "sustainable" land use planning and energy saving opportunities. Sustainable land use planning, also called "smart growth," refers to the application of specific development principles to make prudent use of resources and create genial, low impact communities through enlightened design and layout. A September 2006 public workshop launched the investigation, intending to identify:

- The extent to which land development processes address energy development, generation, and use.
- Successes and barriers that enhance or reduce sustainable development.
- Research that would identify how existing and new development can efficiently use and plan for electricity, natural gas, and transportation fuels.
- Opportunities to apply land use planning principles that consider energy resources to achieve California's energy policies, goals, and initiatives.

What immediately became obvious is the lack of energy consideration on the part of land use decision making authorities and developers in their planning processes. Energy is not typically highlighted as a smart growth principle, so smart growth planners most often are not including energy in their considerations. Some exceptions exist; however, most planning professionals and the public identify energy—usually electricity or natural gas to cool, heat and light homes and buildings and power equipment and appliances—as a commodity delivered by a service provider, not unlike water and garbage pick up. The host of related support services and infrastructure, such as fueling stations, transmission lines, power plants and pipelines, are rarely considered in planning uses for parcels of land.

Until very recently, most land use and development decisions were relics of a post-World War II legacy of sprawling suburbs to accommodate the post-war baby boom and economic prosperity. Even as urban development and land use planning came into vogue as a university curriculum, a profession, and a political and economic tool, energy was not a priority consideration. Transportation issues became a new focus with the oil crises of 1973 and 1979. Planners concentrated on increasing density, changing zoning to allow for mixed use development, and building near transit stations to reduce the number of vehicle miles traveled (VMT), thus reducing fuel consumption and air pollution and decreasing roadway congestion.

While the potential to reduce greenhouse gas (GHG) emissions by decreasing fuel use cannot be overlooked,[131] that action alone is not enough to meet greenhouse gas reduction goals and reverse negative global climate changes. The burden that a burgeoning population places on energy supply and infrastructure demands a fundamental shift in approaches to land use and development.

Today, as California makes plans to accommodate growth, smart growth is proving to have potential as a powerful, innovative, and largely untapped tool, much as Title 24 has been an extremely effective tool in reducing energy demands of residential and nonresidential buildings.[132] By including energy demand, supply, and infrastructure as central factors in the land use planning equation, the state and local governments can make intelligent use of all resources and meet energy-related goals. Broadening the definition of smart growth to encompass *all* energy saving strategies is a first step in that direction. Increasing on-site production of renewable energy (including solar roofing tiles), using distributed generation (DG),[133] and employing energy and resource efficient design approaches[134] are but a few non transportation-related strategies that would fall under a broader definition and produce significant energy savings.

This chapter first describes California's current land use planning processes and the challenges affecting greater use of smart growth. Where possible, the chapter quantifies

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[131] In a 2001 report, California Smart Growth Energy Savings MPO Survey Findings, the California Energy Commission found that California can reduce statewide transportation-related energy consumption between 3 and 10 percent with the implementation of smart growth policies across the state. To do so would save 60 to 237 trillion BTUs, or between 0.6 and 2.3 billion gallons of fuel annually. This is equivalent to saving between 3.3 and 11.1 million metric tons of carbon dioxide or taking between 1 and 3.8 million cars off California roadways. California Energy Commission, 2001, http://www.energy.ca.gov/reports/2002-02-06_600-01-021F.PDF.

[132] The Energy Efficiency Standards for Residential and Nonresidential Buildings were established in 1978 in response to a legislative mandate to reduce California's energy consumption. The standards are updated periodically to allow consideration and possible incorporation of new energy efficiency technologies and methods.

[133] Distributed energy resources are small-scale power generation technologies (typically in the range of 3 to 10,000 kilowatts) located close to where electricity is used (a home or business) to provide an alternative to or an enhancement of the traditional electric power system.

[134] Energy-efficient measures would include site planning features (orienting residences in relation to the sun, street width, landscaping, tree cover, placement of streetlights, maintenance of natural drainage courses) and construction practices (building materials, glazing, insulation levels, ductwork, high efficiency air conditioning equipment, windows).

the energy benefits of smart growth, although benefits quantified to date are largely related to the reduction of vehicle miles traveled. The chapter looks at ways to expand the integration of land use and energy and makes recommendations for future policy and action. The significant role of local governments in land use planning decisions, the importance of their continuing in that role and broadening it to include development of local GHG reduction plans, tapping the expertise of utilities, and expanding tools such as software and planning systems are a few of the powerful measures the chapter explores and recommends.

## Current Land Use Strategies Fail to Address Energy

To date, land use planning has not incorporated energy considerations to any significant extent. In fact, the planning for land use has been essentially independent of the planning and delivery of energy. Our legacy of sprawling development is primarily a product of the last six decades. Post-World War II demand for housing spurred suburban growth, facilitated by the increasingly widespread use of private automobiles and an inexpensive energy supply. An increasing energy need and inexpensive supply mirrored economic growth and enriched lifestyles and led to developments that:

- Consume resources inefficiently as compared to other development patterns.
- Use excessive amounts of land per household and increase the per household cost of utility infrastructure.
- Foster the automobile as the preferred means of transportation over other alternatives.
- Produce development patterns that do not take advantage of or create site conditions that could have a positive effect on energy use or energy production.
- Array land uses in ways that do not allow for effective implementation of dispersed energy generation and capture.

Challenges to planning and implementing different, more energy-sustainable development patterns include the following:

- Resistance of consumers to certain housing styles.
- Resistance to changing development formulas that appear to have widespread support and demand.
- Transportation modeling tools that do not accurately characterize the effects of higher density developments in transit-rich areas.[135]

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[135] David B. Golstein PhD., John Holtzclaw, and Todd Littman, *Overcoming Barriers to Smart Growth: Surprisingly Large Role of Better Transportation Models*, August 2006.

- Differing opinions as to the acceptability of higher density developments
- Perception that energy is not a land use issue.
- Building codes that may be out of step with the needs of more compact development.
- Potential resistance of consumers to invest in up-front capital costs for energy saving aspects of alternative land use developments.
- Safety codes that dictate road widths in direct contrast to the narrower, more pedestrian-friendly roadways of smart growth developments.
- Lack of a law that requires general plans to comprehensively address energy as an element in the plan.
- The low priority designation of energy in the general plan in those cases where it is discussed, such as relative to transportation.
- The California Environmental Quality Act's lack of a requirement that energy be addressed as part of the environmental process.

# Land Use Planning and Development Today

Most of today's cities, towns, and communities and manufacturing, commercial and residential neighborhoods evolved from a patchwork of natural resources, need, geography, climate, convenience and imagination. More recently, local general plans have guided land use and development decisions. Whether planned or random, the permanent nature of these land use choices will dictate energy requirements for generations to come. Only in the last decade or so have planners and developers begun to appreciate the effect of their land use decisions on our energy resources, including the related infrastructure. While methods exist to improve energy efficiencies in current land uses, the largest per capita benefits of energy-aware planning and development are found in pending and future growth, where efficiency can be built in from the outset.

## *How Land Use Decisions Are Currently Made*

While state laws outline the framework within which land use authority is to be exercised, local government is the entity primarily charged with land use decisions. This decision making authority derives from police powers established in common law and set forth in the California Constitution. Local authority is divided between incorporated cities and towns and unincorporated areas of a county, with each having responsibility for its geographic area.[136] The planning process involves the development of general plans and specific plans; imposition of zoning; subdivision of land; development

[136] California Constitution article XI, section 7

agreements; and the review of environmental impacts.[137] State laws outline this process; it is the responsibility of local agencies to apply it.

## The General Plan Lays the Foundation of Planning for Land Use

The local general plan is the single most important planning document in a community. As a statement of development policies for a locality, the general plan sets forth objectives, principles, standards, and proposals. The plan is required by law to have seven elements: land use, circulation, housing, conservation, open space, noise, and safety. No specific state mandate requires that a general plan include an energy element. Only about 10 percent of California's general plans include energy elements, and over half of the state's jurisdictions have general plans more than 10 years old.[138]

The Legislature and the courts require that land use decisions be guided by the general plan, but the state leaves to local legislative bodies decisions on the form of the general plan and the actions to be taken under it. A specific plan defines a smaller portion of a community's planning area for more detailed implementation of the general plan. To be considered legally valid, land use actions such as the zoning ordinance, tentative map, development agreements, and exactions must be consistent with the general plan.

## Zoning Dictates How Land Is Used

Zoning ordinances divide cities into districts and apply particular regulations in each district. Each zone may have regulations regarding the height or bulk of structures and regulations that prescribe the uses to which buildings may be put. Zoning must be consistent with the general plan and, if applicable, the specific plan for an area. Zoning typically enumerates allowed uses, but provides administrative processes for variances to the zoning or to obtain a permit for a conditional use.

Jurisdictions also have the authority to work with a developer to establish a development proposal that incorporates multiple uses within a single coherent plan. This allows a city to achieve desired outcomes that it otherwise might not achieve under traditional zoning. This approach is useful in creating a mixed-use development that integrates commercial and office uses with residential uses to create a village with its own design principles and internal coherence. Increasingly, developers of larger parcels are negotiating with cities to establish mutually agreeable development plans that address housing needs and associated commercial services, jobs, infrastructure, open space, and other community amenities.

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[137] Government Code sections 65100 et seq., 65300 et seq., 65800 et seq., 65410 et seq., 65864 et seq.

[138] Roberts, T. 2006. Remarks presented at Land Use and Energy Workshop, California Energy Commission, September 22, 2006

## Environmental Reviews Are Not Required to Address Energy

The planning process may require an environmental review at various points. The California Environmental Quality Act[139] (CEQA) requires officials making discretionary decisions—such as the adoption of a general or specific plan or a plan amendment—to consider the environmental consequences of their decision. However, "the environment" in this case does not mean "energy." CEQA requires the evaluation of 17 environmental elements; energy is not included (although Appendix F of the CEQA guidelines does state that environmental impact reports must include a discussion of the potential energy impacts of proposed projects).

## Land Use Involves Multiple Parties

Although the state leaves the planning details to local government, it can and does impose specific requirements on local government to further state policies and objectives. Energy efficiency thresholds for buildings, health and safety standards, and mandatory recycling goals for solid waste are examples of such potential requirements, which may be in the form of dictates or conditions that must be met to receive particular funds.

Local governments control and administer local development, but are generally not themselves developers. Rather, they respond to development proposals by others, negotiating in the interests of the community and approving, modifying, or denying a developer's application. Through general and specific plans, zoning, and other land use planning mechanisms, local officials establish the guidelines within which private sector corporations, partnerships, and individuals may undertake development.

On a broader scale, local governments that share common interests and concerns have formed voluntary intergovernmental associations. These councils of government, or COGs, are comprised of counties and cities within a defined area. They bring together regional leaders and decision makers to examine regional and local issues. The COGs, however, lack direct authority over planning and land use decisions. Rather, COGs offer a venue for the discussion of regional issues and provide data and guidance to municipalities. There are 31 COGs in California.

Because transportation is an important regional concern, Metropolitan Planning Organizations (MPOs) were established as a region's transportation planning body and as a vehicle for the dispersal of federal transportation funding to that region. There are 18 MPOs in California. Unlike COGs, MPOs have considerable influence on the location of transportation infrastructure and thus development, thanks to their role as a source of funding for transportation projects. There are 13 COGs and MPOs that cover identical

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[139] California Environmental Quality Act. Public Resources Code section 21000 et seq., California Code Regulations Title 14; sections 15000 – 15387 (CEQA Guidelines).

areas and are a single entity, such as the Sacramento Area Council of Governments and San Diego Association of Governments.

COGs and MPOs, while not having direct land use planning authority, can influence planning. A number of these entities have begun using the Regional Blueprint Planning Program sponsored by the U.S. Department of Transportation (U.S. DOT) and the California Department of Transportation (Caltrans). The program provides funds to MPOs that in collaboration with their respective COGs, prepare regionwide plans based on consensus. The process relies on a large public participation component in the planning process (20 to 25 percent of the budget). The Blueprint program does not focus exclusively on transportation, but works to create a regional vision of the preferred land use pattern and offers potential to expand to include additional subject areas, including energy considerations.

Investor-owned and publicly owned utilities (IOUs and POUs, respectively) are responsible for meeting energy demand and planning how to meet future needs. Utilities have a keen understanding of the processes for delivering natural gas and generating and delivering electricity. They know the strengths and weaknesses of their infrastructures in relation to past and future growth. As such, utilities can be a resource to local planners in understanding the energy implications of land use decisions, including the demand created by new development and the cost of infrastructure to serve this growth. Additionally, IOUs are tasked with assisting customers to conserve energy via the use of public goods charge (PGC) funds. The PGC is a nonbypassable surcharge imposed on all investor-owned utility retail electricity and natural gas sales to fund energy efficiency activities, development of renewable resources, and energy research, development, and demonstration activities that are in the public interest and which are not otherwise being funded. As described later in this chapter, the IOUs have just begun to explore how these funds could be used to assist their customers in reducing energy use through better land use planning.

Finally, consumers play a role in determining the patterns of growth through their decisions to purchase, rent, or otherwise “vote with their dollars” for the built environment. In doing so, consumers weigh the cost of acquisition and operation against location, amenities, schools, access to transportation, distance to jobs, and myriad other factors. While the cost of energy, and the environmental effects of supplying and using energy, may play a role in their choices, it is but one of many factors—and not necessarily the most important.

## Smart Growth Is an Integral Component of Reducing Greenhouse Gas Emissions

Assuming that all new U.S. housing were smart growth, with half greenfield and half brownfield,[140] the total nationwide savings after 10 years, based on a projected level of 24.3 million housing starts from 2005–2020, would be in the range of 977 trillion miles of travel reduced; 5,690,000 trillion Btu saved; 49.5 billion gallons of gasoline saved; 1.18 billion barrels of oil saved; 595 million metric tons of $CO_2$ (MMTCE) emissions reduced; and $2.18 trillion savings.[141] Obviously, all new homes are not smart growth, and more realistic goals are being set.

With the recent signing of Assembly Bill 32 (Nuñez), Chapter 488, Statutes of 2006, California will embark on its own ambitious program to reduce GHG emissions. The Governor's Climate Action Team identified smart land use and intelligent transportation systems as major elements of a unified program to meet the goals of AB 32. Initial evaluation suggests that the land use/intelligent transportation systems element of the state's strategic growth plan could reduce congestion 20 percent or more on state highways when fully implemented. This would correspond to significant reduction in average vehicle miles traveled on the system, eliminating several million tons of $CO_2$ emissions from mobile sources. Suburban smart growth measures could reduce household vehicle miles traveled between 10 and 30 percent, and urban infill and related measures could reduce vehicle miles traveled by 30 to 50 percent.[142]

In the *Climate Action Report*, the land use and intelligent transportation systems strategies are projected to result in reductions of 1.77 MMTCE $CO_2$ by 2010 and 14.5 MMTCE by 2020.[143] These projected reductions represent a major portion of the total GHG reduction goal. Table 6 highlights those energy-related strategies which could yield the largest potential reductions.

Many of the strategies noted in Table 6 are directly linked to smart growth and energy efficiency. Success in reaching the smart land use and intelligent transportation systems goals will be critical to meeting the directives of AB 32. Measures to reach these goals include:

- Promoting jobs/housing proximity and transit-oriented development.
- Encouraging high density residential/commercial development along transit/rail corridors.

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[140] Land sites located within developed urban areas.

[141] Mary Jean Bürer and David B. Goldstein, Natural Resources Defense Council and John Holtzclaw, Sierra Club, *Location Efficiency as the Missing Piece of the Energy Puzzle: How Smart Growth Can Unlock Trillion Dollar Consumer Cost Savings*.

[142] State Agency Work Plans, February 2006, http://www.climatechange.ca.gov/climate_action_team/reports/2006-02-06_AGENCY_WORKPLANS.PDF.

[143] These numbers reflect recent updates by the California Department of Transportation to the numbers in the *Climate Action Report*.

- Implementing intelligent transportation systems, traveler information/traffic control, and incident management.
- Accelerating the development of broadband infrastructure.
- Comprehensive, integrated, multimodal/intermodal transportation planning.

**Table 6. Energy-related Strategies Showing Largest Potential Greenhouse Gas Reduction**

| | 2010 GHG Goals (MMTCE) | 2020 GHG Goals (MMTCE) |
|---|---|---|
| Smart land use and intelligent transportation systems | 1.77* | 14.5* |
| Transportation energy efficiency | 1.8 | 9 |
| Accelerated Renewable Program Standards (33%) | 5 | 11 |
| IOU additional energy efficiency programs | 1 | 8.8 |
| Publicly owned utilities carbon policy | 3 | 9 |
| Vehicle climate change standards | 1 | 30 |
| * Revised numbers provided by Caltrans, December 2006. | | |

Source: California Climate Action Team.[144]

As noted in the Climate Action Team's final report to the Governor, many participants at the Climate Action Team public meetings indicated that smart growth/smart land use and increased transit availability should be a priority in the state.

Many independent groups already have established smart growth principles, including the Local Government Commission's Ahwahnee Principles; the National Governors' Conference Principles on Smart Growth; the League of California Cities' Principles for Smart Growth, and the American Planning Association's Smart Growth Principles.[145] The Ahwahnee principles, for example, include community, regional, and implementation principles. Among the 15 community principles are those that call for planning complete and integrated communities with multiple uses essential to daily life; establishing communities sized to allow easy walking to activities; and providing for a diversity of housing types.

[144] Ibid.
[145] http://www.planning.org/policyguides/smartgrowth.htm.

## Utilities in Land Use Planning

For the most part, utilities respond to land use decisions as opposed to driving those decisions. Many utilities are getting involved in general plan updates and other planning endeavors which address smart growth issues. However, utility planning done on an annual basis will likely not be synchronized with the timing of local jurisdiction planning. Southern California Edison's (SCE) Cooperative Planning Project is an effort to harmonize SCE planning with local government land use planning. Similarly, the Sacramento Municipal Utility District (SMUD) has undertaken an active role in the ongoing update of Sacramento County's General Plan.

All three of the state's IOUs have major energy efficiency programs with some level of incentives or rebates. These programs are now incorporating sustainable development concepts. SCE, Southern California Gas (SoCalGas) and San Diego Gas and Electric (SDG&E) are initiating "sustainable communities" programs, which offer a higher tier incentive for green building projects that significantly exceed Title 24 standards. Qualified projects will incorporate high performance energy efficiency and demand reduction technologies, along with clean on-site generation, water conservation, transportation efficiencies, and waste reduction strategies.

The utilities are forming partnerships with cities and other entities to incorporate sustainability concepts in communities.[146] In 2006, SoCalGas will work jointly with SCE on a sustainable communities program for the City of Santa Monica. SoCalGas plans to continue collaborations with the Energy Coalition, Bakersfield/Kern County Energy Watch, the South Bay Cities Energy Efficiency Savings Center, and the Ventura County Regional Energy Alliance, among others. SDG&E is partnering with the City of San Diego, the City of Chula Vista, and the County of San Diego and will test expedited permit processing for construction projects that exceed Title 24 standards. Pacific Gas and Electric (PG&E) has identified 17 local government partnerships and 3 statewide government partnerships for its 2006–2008 partnership portfolio.

POUs also promote energy efficiency and, because they are owned by the communities, often have greater visibility and integration in local planning. For example, SMUD is working closely with the City of Sacramento in the early stages of a major new residential/commercial/industrial development in the former rail yards area, particularly as to the feasibility of building a district heating and cooling facility as part of the project.

Some POUs outside California are moving even more aggressively. The Austin, Texas city council has created a zero-energy taskforce to look at adopting a building code

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[146] California Public Utilities Commission, Decision 05-09-043, *Interim Opinion: Enery Efficiency Portfolio Plans and Program Funding Levels for 2006-2008 – Phase 1 Issue*s, September 22, 2005, http://www.cpuc.ca.gov/published/Final_decision/49859.htm.

change that would require all new single family homes to be "zero-energy capable" by 2015.

## Current Efforts to Integrate Land Use Planning with Energy Concerns

Consideration of energy concerns in the land use planning process requires local governments to imbed the state's energy goals in their decisions. Local agencies must also take up the GHG reduction challenge. A myriad of planning tools, new research, and new partnerships can support local and state government efforts to reach those goals. Probably the single largest opportunity resides with smart growth.

Smart growth recognizes that current land use strategies are failing to produce or facilitate changes needed to effectively address integrated resource issues. Moving from the sprawling developments of the past to new smart growth developments that fully consider energy issues can create sustainable communities for the citizens of this state and also provide major reductions in GHG emissions, thus ensuring a better future for California's growing population.

### *State and Local Initiatives to Advance Smart Growth and Energy Initiatives Are Increasing*

California took a major step toward smart growth with the passage of Assembly Bill 857 (Wiggins), Chapter 1016, Statutes of 2002, which laid out three planning priorities: promote infill development and social equity in existing communities; protect and conserve environmental and agricultural resources; and achieve more efficient use of land, transportation, energy, and public resources outside the infill areas. In response to AB 857, the Governor's Office of Planning and Research (OPR) updated its Environmental Goals and Policy Report (EGPR) to make it consistent with the three AB 857 planning priorities.[147] All state departments and agencies must comply with the goals and policies of the EGPR and plan in a manner consistent with the three planning priorities laid out in AB 857. The EGPR is to be the basis for judgments about the design, location, and priority of major public programs, capital projects, and other actions, including the allocation of state resources through the budget and appropriations process.

Local communities are also beginning to consider energy issues in land use and in furthering smart growth and climate change plans. A number of cities and counties have energy elements in their general plans or consider energy extensively in other, related elements. In 2002, as part of the Pacific Gas and Electric Local Government Energy

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[147] "Governor's Environmental Goals and Policy Report," November 2003. Office of Planning and Research, http://www.opr.ca.gov/EnvGoals/PDFs/EGPR--11-10-03.pdf

Efficiency Program (LGEEP), the Local Government Commission (LGC) developed a report, *General Plan Policy Options for Energy Efficiency in New and Existing Development*, to help local governments develop energy elements in their general plans.[148] A few examples of energy elements serve to illustrate the wide variety of goals, objectives, and strategies that can be included in such elements.

### County of Humboldt

The county, with assistance from the Redwood Coast Energy Authority, has developed a detailed energy element establishing goals and objectives that lay out with some specificity how energy concerns are to be included in the planning process.[149] The element sets out four goals: strategic energy planning; energy efficiency and conservation; renewable energy, distributed generation and cogeneration; and local management of energy supply. A comprehensive list of objectives supports these goals and speaks to a range of concerns and values motivating the county, including:

- Regional energy authority
- Emergency preparedness planning
- Energy-related research and economic development
- Planning of active and healthy communities
- Countywide site design standards
- Energy education and policy dissemination
- Public services, facilities, and operations
- Building
- Water, wastewater, and solid waste management
- Renewable energy, distribution, and cogeneration
- New energy production and transmission facilities
- Local utility development and management options

### City of Pleasanton

Pleasanton's general plan energy element states that its purpose is to guide Pleasanton toward a sustainable energy future.[150] The element's goals—attaining a sustainable energy future using many different strategies and saving transportation energy by implementing a more effective transportation system—are supported by objectives that, among other things:

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[148] The Local Government Energy Efficiency Program pilot program provided resources and technical support to local governments to help them increase energy efficiency in new residential construction.

[149] http://www.redwoodenergy.org/uploads/Energy%20Element%20Draft%208-05v2.pdf#search=%22humboldt%20county%20regional%20energy%20authority%22.

[150] http://www.ci.pleasanton.ca.us/pdf/genplandraftenergyelement.pdf.

- Promote efficiency and conservation through education and establish guidelines, regulations, programs, and incentives to increase efficiency and conserve energy.
- Promote local power sources such as solar, photovoltaics, and distributed generation.
- Require that commercial buildings over 20,000 square feet incorporate measures from the U.S. Green Building Council Leadership in Energy and Environmental Design (LEED) Rating System.

### City of Pasadena

Pasadena's energy element enumerates a number of strategies to achieve its energy objectives,[151] including:

- A statement that energy conservation will have equal consideration with all other development criteria in evaluating projects.
- Consideration of solar access.
- Encouragement of energy efficient land development.
- Providing incentives to developers to promote ride sharing and the use of public transportation.

### City and County of San Francisco

The environmental protection element in San Francisco's general plan includes an energy section.[152] The city's energy policy is designed with four goals: more efficient use of energy; balance of energy supplies to meet local needs; economic development; and responsible community participation. The objectives are:

- Establish San Francisco as a model for energy management.
- Enhance the energy efficiency of housing.
- Promote effective energy management practices to maintain economic vitality.
- Increase the energy efficiency of transportation and encourage land use patterns and methods of transportation that use less energy.
- Promote the use of renewable energy.
- Support energy programs that are equitable and encourage conservation and renewable energy use.
- Develop financing opportunities to implement local energy programs.

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[151] http://icma.org/upload/library/IQ/117390.htm
[152] http://www.sfgov.org/site/planning_index.asp?id=25527

## Los Angeles Area

The Southern California Association of Governments (SCAG) initiated a growth visioning process in 2004 (the Southern California Compass) to better link transportation and land use. The resulting policies shaped the framework for SCAG's 2004 Regional Transportation Plan. Compass land use actions adopted in the 2004 Regional Transit Plan were projected to reduce VMT by 7,000,000 and fuel consumption by 858,240 gallons, as calculated on a per day basis for the year 2030.[153] SCAG is currently preparing a Regional Comprehensive Plan that will address energy issues, including possible future constrained petroleum supplies. To help guide the energy analysis, SCAG has assembled an Energy Working Group and has also contracted to estimate energy supply and demand through 2035.

## Chula Vista

The City of Chula Vista has garnered considerable attention for its innovation in implementing strategies that address the role of land use in energy. The city "aims to become a national and global model of community-scale energy efficiency and sustainable resources management."[154] A team of planners, architects, engineers, and developers are formulating "energy-smart" designs for large-scale developments on 1,500 acres, the first in a series of high efficiency, low impact communities targeted for a 6,000-acre tract that eventually will house over 70,000 residents. The city was selected as the site for the National Energy Center for Sustainable Communities, a collaboration of the city with the U.S. Department of Energy, the Center for Energy Studies at San Diego State University, and the Gas Technology Institute.

## San Diego Region

A new Regional Comprehensive Plan developed through the auspices of the San Diego Association of Governments (SANDAG) and adopted in 2004 is helping guide regional growth in the San Diego area. An outgrowth of the plan, a "Smart Growth Concept Map" is used to visualize where smart growth can occur supported by the transportation investments.[155] Nearly 200 existing, planned, or potential smart growth projects are identified. These include metropolitan and urban centers, town and community centers, rural villages, mixed use transit corridors, and special uses centers. The map is an important tool in developing the 2007 update of the regional transportation plan.

The San Diego region has long recognized the necessity of addressing regional energy issues. The San Diego Regional Energy Office implements programs, provides information, and fosters public policies to facilitate the adoption of clean, renewable,

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[153] Southern California Associations of Governments, correspondence to the California Energy Commission, September 21, 2006.

[154] Engle, D. 2006. "With the Power at Hand: Examining the Merits of Distributed Energy," *Planning*, American Planning Association.July 2006.

[155] http://www.sandag.org/uploads/publicationid/publicationid_1252_5841.pdf.

sustainable, and efficient energy technologies and practices. Since 1978, four energy plans have been developed for the region. The most recent plan, the 2003 Regional Energy Strategy, addresses goals for electricity and natural gas supply, demand, and infrastructure and goals for public policy. To coordinate the implementation of the 2003 Regional Energy Strategy, SANDAG formed the Energy Working Group.[156] SANDAG also recently hired an energy specialist in recognition of the importance of energy considerations in planning.

## City of San Diego

The City of San Diego's Sustainable Community Program incorporates sustainable policies and procedures and measures outcomes through a series of indicators and a Climate Protection Action Plan. Primary target areas include energy efficiency and renewable energy and alternative vehicles and fuels.[157] The Climate Plan, developed in 2005, includes the city's GHG Emission Reduction Program, which sets a reduction target of 15 percent by 2010, using 1990 as a baseline.[158] Although most of the actions are directed toward City of San Diego activities and facilities, Resolution 600-39 states that "the City aims to direct growth into compact patterns of development, where living and working environments are within walkable distances. The City shall apply the 'Transit Oriented Development Design Guidelines' which are designed to reduce auto trips to work, roadway expansion and air pollution."

## City and County of San Luis Obispo

San Luis Obispo County has an energy element in its general plan and is in the process of revising its conservation element. As a part of this process, the county will incorporate the existing energy, offshore energy, agriculture and open space elements. The element will be updated to include green building and land use policies that will implement smart growth.[159] The San Luis Obispo County Department of Planning and Building is now offering expedited processing of projects that comply with smart growth principles. The City of San Luis Obispo has adopted the Ahwahnee Principles,[160] and the Mayor has signed the U.S. Mayors Climate Protection Agreement.[161]

In October 2006, a Smart Energy Solutions Summit was held in San Luis Obispo that involved government agencies, utilities, renewable energy product manufacturers, environmental organizations, banking and mortgage interests, chamber of commerce members, and residents within the San Luis Obispo area. Topics for discussion included land use planning as a tool to reduce energy consumption, new vehicle/transportation

[156] http://www.sandag.org/index.asp?committeeid=67&fuseaction=committees.detail.
[157] http://www.sandiego.gov/environmental-services/sustainable/index.shtml.
[158] City of San Diego Climate Protection Action Plan, July, 2005, http://www.sandiego.gov/environmental-services/sustainable/pdf/action_plan_07_05.pdf.
[159] San Luis Obispo County Update, Morgan Rafferty, Environmental Center of San Luis Obispo, October 16, 2006.
[160] http://www.lgc.org/ahwahnee/principles.html.
[161] *Additional Update on San Luis Obispo Smart Energy Growth*, Nick Alter, June 17, 2006.

options, community choice ordinances related to purchasing renewable energy, and how building local will change the energy future. Local organizations such as San Luis Obispo Green Build and ECOSLO discussed green building options that incorporate energy efficiency and renewable energy in building design and construction. California Polytechnic State University has a Renewable Energy Institute that promotes teaching, research, development, and community service in solar and renewable energy technologies and sustainable community infrastructure.

### Santa Monica

In March 2006, Santa Monica's City Council approved a Community Energy Independence Initiative and authorized implementation of a two-year demonstration project to verify potential program benefits and develop proposed financing and full scale implementation plans for the initiative. In September, the council moved to hire a contractor to move forward with the program. The goal of the project is to push the city toward generating all the electricity it currently consumes.

### Non-Government

The American Planning Association (APA) recently collaborated with the Environmental and Energy Study Institute (EESI) to survey local planners on energy issues. The survey results indicated that planners believe that energy is very connected to their jobs but that they need tools, training, and support to more effectively promote energy efficiency and reduce energy use. APA and EESI will work together to educate planners about energy efficiency practices and available renewable energy options. This represents an additional forum for collaboration.

The Local Government Commission has also been coordinating quarterly energy networking meetings for local governments since 2002. It is currently developing the Local Government Sustainable Energy Coalition to enable California public entities to share information and resources to strengthen and leverage their communities' commitments to a sustainable energy future—a future that provides for essential energy resources, restrains energy demand, increases energy efficiency and renewable energy production, and improves energy security and reliability, while enhancing environmental values and community well-being.

## *The Variety and Scope of Planning Tool Development Is Promising*

Many tools exist and are emerging to help support energy consideration in local planning decisions. In the 1990s, the Energy Commission developed and supported a geographic information systems land use planning software program called Planning for Community Energy, Economic, Environmental Sustainability (PLACE3S) to help smart growth decision making throughout California. In 2002, this tool was upgraded to an Internet-based version—I-PLACE3S—which uses various technologies to increase its accuracy and data volume capabilities and decrease calculation time. The Commission's I-PLACE3S program has been an important and useful part of the Blueprint process. Because it is scenario based, it allows for comparisons of potential future outcomes using different growth and land use assumptions. I-PLACE3S clearly demonstrated its usefulness by playing a prominent role in the Blueprint work recently completed in Sacramento. I-PLACE3S is currently being updated to include a building energy module.[162]

Several planning tool research efforts are currently underway:

- The Energy Commission, through its Public Interest Energy Research (PIER) program, is funding work by EcoInteractive to integrate energy planning capacity into I-PLACE3S so that local government planners (COGs and MPOs) and decision makers across a region will be able to view the outcomes of building energy analyses alongside established key planning data such as housing costs, vehicle miles traveled, jobs to housing ratios, and air emissions.
- For local jurisdictions, the water system may represent over 50 percent of total energy use.[163] New sources of water such as water produced through desalination are likely to be energy intensive. PIER is funding the expanded analytical capacity of the Water Energy Sustainability Tool. This modeling tool will assess the life-cycle costs of the water system and various water supply options. The tool is primarily designed to assist water utility managers in making better energy and environmental decisions related to the water system.
- Within the next 25 years, the U.S. population will design and construct more than 213 billion square feet of space, presenting an opportunity to design and build to a new level of energy and resource efficiency. PIER is funding a project in Chula Vista to look at more efficient site design. The project will demonstrate the use of four different modeling tools (Building Energy Analyzer, Energy-10, City Green, and CommunityViz) combined to optimize energy, economic, and environmental parameters; analyze impacts of efficient community designs on utility infrastructure; and identify solutions to institutional and market barriers. The project will include stakeholder reviews and feasibility analyses that incorporate input from city officials, builders, developers, and others. Case studies and guidelines that describe ways to optimize energy and resource efficiency in site design are anticipated.
- Other tools exist to support local governments in reducing their GHG emissions. The International Council for Local Environmental Initiatives (ICLEI) Local Governments for Sustainability program supports local governments in developing plans to reduce their GHG emissions using the Clean Air Climate Protection (CACP) software. This software is used to store, organize, and analyze data for larger efforts

[162] California Energy Commission, http://www.energy.ca.gov/places/index.html.
[163] California Energy Commission, *Sustainable Urban Energy Planning: A Roadmap for Research and Funding,* June 2005, CEC-500-2005-102, http://www.energy.ca.gov/pier/final_project_reports/CEC-500-2005-102.html.

to develop local emissions inventories, evaluate proposed measures/scenarios, and develop or evaluate policy and local action plans. The tool calculates GHG and criteria air pollutant emissions from thousands of emissions factors. ICLEI is developing another tool, the Harmonized Emissions Analysis Tool, which will be an Internet-based resource for storing, tracking, modeling, and reporting emissions and reductions of GHGs and criteria air pollutants. Forty-seven California cities are currently participating in ICLEI.

- CTG Energetics' Sustainable Communities Model™ quantifies the relative environmental impacts of a broad variety of design decisions ranging from the master plan land use level to the design of single buildings. It quantifies the actual environmental impacts and linkages of various development decisions; analyzes environmental and economic costs, savings, synergies and trade-offs; and optimizes the sustainability/cost ratio.[164]
- The California Local Energy Efficiency Program (CALeep) was developed to help California's local governments design and implement highly effective energy efficiency strategies for their communities. The CALeep Workbook describes a basic five-step process that communities can follow to increase their level of energy efficiency activity.[165]
- The U.S./Green Building Council is the leading green building certification organization in the country and has developed a program called Leadership in Energy and Environmental Design for Neighborhood Development (LEED–ND). This program establishes a rating system that awards points for building designs, new commercial construction, major renovations, and existing building operations and commercial interiors that incorporate principles of energy production, use and efficiency found in the smart growth, urbanism, and green building programs. LEED–ND is being developed in partnership with the Natural Resources Defense Council and the Congress for New Urbanism. Development projects are rated based upon their location efficiency; environmental preservation; compact, complete and connected neighborhoods; and resource efficiency. The rating system combines the elements of smart growth, new urbanism, and green building into the first national standard for neighborhood design. LEED-ND will create a label which could serve as a concrete signal of, and incentive for, better location, design, and construction of neighborhoods and buildings.
- The federal government's Blueprint approach offers potential for use beyond the development of transportation plans, as originally intended. The Sacramento Area Council of Governments has recently completed its Blueprint plan, one that relied on extensive modeling and a large public participation program conducted throughout the region. The recent Regional Comprehensive Plan in the San Diego area is another

[164] http://www.ctg-net.com/energetics/News/CTG_Sustainable_Communities_Model.htm
[165] CaLeep Notebook, March 2006.
http://www.caleep.com/docs/workbook/CALeep%20Workbook%20Exec%20Sum%20Final%20050106.pdf.

Blueprint planning effort. The eight-county San Joaquin Blueprint Planning Process is underway and will address transportation and other growth issues throughout the San Joaquin Valley. The process is not limited to large urban areas. For example, Shasta County has made a grant application to U.S. Department of Transportation for Blueprint funding.[166]

## The Need Exists for New Research on Fundamental Aspects of Land Use and Energy

In June 2005, the Energy Commission released a consultant report entitled *Sustainable Urban Energy Planning: A Roadmap for Research and Funding*.[167] This roadmap identified areas of specific needed research, focusing on the connection between municipal governments and electricity use. As noted in this roadmap and by many attendees and commentators at the Energy Commission's September 22, 2006, workshop, more information in this area is needed.

More specifically, there is a need to better understand the relationships, processes, and outcomes that underlie smart growth and energy. Research is needed to identify, quantify, evaluate, and verify sustainable energy-efficient planning practices, neighborhood and residential design components, and the energy used to construct, operate, and maintain various building types. Further, information is needed to better understand the associated energy relationships, interdependencies, efficiency, and environmental enhancement opportunities of these practices and designs. Tools and methods are needed to identify and set energy sustainability goals, as well as to verify that these goals are met. Research needs to take a comprehensive approach, using life-cycle studies or system analyses to identify the costs, benefits, and trade-offs of achieving these goals and to allow for more informed decision and policy making.

Key questions from September's Land Use and Energy workshop include:

- What are the interrelationships of energy, land use, and transportation planning? To date, transportation has been the main link between land use and energy, largely because federal law requires that air quality be considered in transportation plans in order to receive federal highway money in non-attainment areas. Efforts to reduce congestion and improve air quality are considered in metropolitan transportation plans and regional Blueprints with the end result being future reductions in vehicle miles traveled and hence transportation fuel use. However, additional links exist, such as energy use associated with the infrastructure, and need to be explored.
- What is the relationship between affordable housing and smart growth? Divergent views exist on whether smart growth enhances affordable housing. Certainly,

[166] http://scrtpa.org/Blueprint%20Planning%20Program%20Description.doc.
[167] California Energy Commission, http://www.energy.ca.gov/pier/final_project_reports/CEC-500-2005-102.html.

reducing transportation costs will benefit those with lower incomes since transportation costs are borne most significantly by the low income, who in some cases pay more than one-third of their total household income for transportation.

- What is the relationship between smart growth and smart communities? "Smart communities" are those that use information technology to transform their communities. Similar to smart growth, smart communities can reduce vehicle miles traveled, although that would be accomplished through broadband systems of communications connecting homes, offices, schools, and health care facilities, for example.
- What are the utility energy requirements, impacts on the distribution system, and environmental impacts of alternative urban growth scenarios? This is an area with very little information. Quantifying the energy needed for new developments, the infrastructure required (for example, extension lines, distributed generation, small-scale renewables, combined heat and power) and the associated environmental effects of the energy and infrastructure will help differentiate the various urban growth scenarios.
- What are the quantifiable energy benefits of smart growth? Smart growth energy savings have been quantified to some extent, but typically only with respect to vehicle miles traveled. Quantifying the additional benefits of better planning and design options, reduced use of building materials, proper solar orientation, energy efficiency improvements, distributed generation, and renewable energy would provide a fuller picture of smart growth benefits.
- What processes affect development decisions by private developers, builders, and municipalities? Understanding the steps that municipalities and developers/builders must take to implement smart growth can identify where possible changes could increase smart growth opportunities. For example, if permitting is identified as a key issue for developers, then expedited permitting for smart growth developments could be a major impetus for further development.
- What are the barriers to adoption of smart growth and how can these barriers be addressed? Understanding the extent to which barriers affect smart growth decisions and incorporation of energy considerations in planning and how the barriers have or have not been surmounted will help direct future actions and policies.

In an effort to more fully address some of these important questions and better define research priorities, periodic updates of the PIER Sustainable Urban Energy Planning Roadmap are necessary. These updates will more precisely identify and describe existing and emerging research needs and, in turn, initiate appropriate research.

## Funding Options to Expand Smart Land Use

Fiscal issues are a constraint to both local and regional bodies as well as to developers and home buyers. Rewards and incentives are typically identified as mechanisms that can enhance smart growth and the construction of energy efficient homes. Most funding options are directed toward energy efficiency rather than smart growth. It is important to explore the full range of funding opportunities that could expand smart land use.

Caltrans is funding Blueprint Planning in several communities, which has allowed regional incorporation of smart growth. In its next round of funding, the California Regional Blueprint Planning Program will make available to MPOs $5 million per year for two years (2006 and 2007).[168] Approximately $1 million will be set aside to fund first year grantees. For second year continuing grants, $4 million will be available. These are federal transportation funds that require at least 20 percent local match.

Energy efficient and location-efficient mortgages allow home buyers to obtain larger mortgages by leveraging the dollars they save in reduced transportation fuel costs from locating near transit and in mixed-use developments and from reduced electricity and gas bills through energy-efficiency. Essentially, purchasers are allowed to buy more house if it is an energy efficient building and/or located in an energy efficient location.

The Location Efficient Mortgage® is a mortgage that helps people become homeowners in location efficient communities.[169] The LEM is a trademark of The Institute for Location Efficiency, a national non-profit organization founded by the Center for Neighborhood Technology, the Natural Resources Defenses Council, and the Surface Transportation Policy Project. Until recently, only two California lenders, located in San Francisco and Los Angeles, provided location-efficient mortgages. However, other options are becoming available. For example, a new home development in Sacramento near a light-rail station will offer location-efficient mortgages.[170]

Energy efficient mortgages allow homebuyers to finance cost effective, energy saving measures as part of the mortgage and/or to qualify for a larger loan amount. The Federal Housing Administration (FHA) Energy Efficient Mortgage (EEM) covers upgrades for new and existing homes and is now available in all 50 states. The FHA 203(k) program enables a home buyer or investor to obtain a single loan to finance both property acquisition and complete major improvements after the time of loan closing. The Veteran's Administration (VA) EEM is available to qualified military personnel, reservists, and veterans for energy improvements when purchasing an existing home. Fannie Mae secondary market guidelines permit approved lenders to increase ratios 2

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[168] http://www.dot.ca.gov/hq/tpp/offices/orip/Blueprint_Grant%20_1st_Yr_Application%20_06-07_Final.pdf#search=%22caltrans%2C%20blueprint%20funding%22.

[169] http://www.locationefficiency.com/.

[170] "'Smart Growth' Helps Cut Sprawl, Revive Area," The *Sacramento Bee*, December 17, 2006.

percent on the debt-to-income requirements for EEMs. Freddie Mac allows lenders to use the projected utility savings as a "compensating factor."[171]

Expanding the number of lenders who understand the benefits of energy efficient and location-efficient homes is an important step in expanding the use of energy efficient and location-efficient mortgages. However, other challenges must be overcome to make these mortgages more widely available and accepted. The largest loan amount available for EEMs is $417,000, which in many California areas is not enough to buy a median-priced home, particularly for a first-time buyer. While EEMs have some underwriting and qualifying advantages, they do not have major pricing advantages, such as a reduced mortgage rate, to help to make them more attractive in the marketplace. Finally, although guidelines do exist for including the cost of energy efficient improvements in home appraisals, most appraisers are not aware of and have no experience in using them.[172]

As previously mentioned, utilities are working with communities to provide incentives to advance energy efficiency. Through its Tax Exempt Customer Incentive Program, the San Diego Regional Energy Office provides technical and administrative assistance plus financial incentives to help tax-exempt organizations implement energy efficiency measures between 2006 and 2008. SDG&E's Energy Savings Bid (ESB) program provides financial incentives for SDG&E non-residential customers who install qualifying new, high efficiency equipment at their businesses. Through its Business Incentive Program, SCE has a new "on-bill" financing program, which offers eligible customers the option to finance their energy efficiency projects through an on-the-bill repayment of the cost (after rebate) of installing qualified energy efficiency measures.

SANDAG has developed a Pilot Smart Growth Incentive Program, which in 2005 provided $19 million in funding to 14 local projects. Beginning in 2008, a longer-term, smart growth incentive program totaling $280 million will be funded through the local TransNet half-cent sales tax program.

The Sacramento Area Council of Governments' (SACOG) Blueprint Civic Engagement provides supplemental funding to existing projects by SACOG government agencies and their partners that promote public involvement in smart growth community development. The projects must promote planning and development that is higher density, compact, mixed use, and creates pedestrian friendly communities that preserve natural resources.

Communities could also benefit through profits created by smart growth zoning actions, essentially development fees captured from project proponents at the time land is

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[171] http://www.pueblo.gsa.gov/cic_text/housing/energy_mort/energy-mortgage.htm.

[172] "Challenges in Offering Energy Efficient Mortgages," Kevin Hauber, *The Mortgage House*, October 16, 2006.

upzoned.[173] Smart growth could also be encouraged through measures that provide incentives to local developers such as reduced developer fees for smart growth housing and expedited permitting, both of which would reduce the costs borne by the developer and passed on to the homebuyers.

Other states have identified incentive programs that could serve as models for California. For example, Maryland "Smart Sites" are publicly owned properties located in designated growth areas, known as Priority Funding Areas, with the services and infrastructure necessary to support growth. Typically, they are underutilized, abandoned, or idle sites that offer prime opportunities for infill and redevelopment. Maryland Smart Sites are eligible for an array of state incentives aimed at promoting Smart Growth.[174] The state's "Live Near Your Work" program also provides financial incentives for employees to purchase homes near their workplaces.[175]

## Further Action Is Needed to Integrate Land Use Planning and Energy

In spite of all state and local government and non-governmental efforts, much more can and should be done to couple land use and energy. The following recommendations focus on the central role land use decision processes can play in meeting many of the state's energy goals. Supporting local government as the pivotal players in land use planning, giving local governments responsibility to develop their own GHG emission reduction plans, involving utilities, expanding the repertoire of smart growth tools available to local governments, and pursuing further research are actions that the state and its partners must take if California is to realize the benefits of integrating land use and energy.

### *Require Local Governments to Adopt Greenhouse Gas Emission Reduction Plans*

Local government action is key to achieving the state's energy policy goals and the aggressive GHG emission reductions contained in the Climate Action Team report.

- ✓ 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.

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[173] *Making Smart Growth Work,* Pacific Energy Policy Center, June 2006.

[174] http://www.mdsmartsites.org/.

[175] James R. Cohen, Maryland's "Smart Growth", Using Incentives to Combat Sprawl, http://www.arch.umd.edu/URSP/People/faculty/jcohensgchapter.pdf#search=%22Maryland%20incentives%2C%20smart%20growth%22.

### *Promote and Facilitate Efficient Land Use Practices*

Helping local governments develop and implement energy efficient land use practices and GHG reduction plans will require input from many sources, including local, regional, and state agencies; developers; utilities; homebuyers; lenders; community groups; non-profit organizations; and other interested stakeholders.

- ✓ The Energy Commission should invite stakeholders to participate in an ongoing land use/energy working group that would convene on a regular basis to guide the state's land use and energy research and program development.

Many of California's communities are beginning to address energy use in their land use planning but need help in understanding the options available to them, the available tools they can use, and the benefits that would accrue to both local government and the public.

- ✓ Working with its partners, the Energy Commission should establish a central repository for efficient land use information resources. The Energy Commission should produce case studies and best practices guides to describe the successes of local government land use efforts to reduce energy needs and GHG emissions.

The general plan is the single most important planning document in a community. As a statement of development policies for a locality, it sets forth objectives, principles, standards, and proposals.

- ✓ The legislature should pass legislation to require local governments to include an energy element in their general plans.

Utilities should play a more influential role in the state's movement toward better land use practices.

- ✓ The CPUC should require IOUs to partner with local governments to incentivize smart growth in their service territories. The CPUC should allow IOUs to recover the cost of the partnerships in rates.

- ✓ Under the authority granted by Assembly Bill 2021 (Levine), Chapter 734, Statutes of 2006, the Energy Commission should assist municipal utilities in partnering with local governments to incentivize smart growth in their service territories

Growth, development and planning are multi-disciplinary activities that involve a wide variety of state agencies and authorities. A state agency working group for efficient land use would enable the state to direct its resources and activities in a coordinated manner.

- ✓ The state should form a state agency working group to develop and implement an Efficient Land Use Action Plan for the state. The working group should include, but not be limited to, the Energy Commission, the Governor's Office of Planning and Research, the California Department of Housing and Community Development, the California Air Resources Board and the California Department of Transportation.

### *Provide New Tools and Conduct Research to Assist Local Government's Energy and Greenhouse Gas Reduction Planning Efforts*

Over the next several years, the Energy Commission will fund research projects that bolster local and regional governmental energy and GHG emission reduction planning efforts. Direction for research and tool development will come, in part, from the stakeholder group described above and should provide the scientific and technological background to inform sound decision and policy making in California.

- ✓ The Energy Commission should complete the update of the I-PLACE3S energy module and then continue to provide research and analytical tool development that will give the state and its partners the ability to:

  - Better understand the relationships, processes, and outcomes that underlie land use development and energy.
  - Identify, quantify, evaluate, and verify sustainable energy planning practices and designs.
  - Understand the associated complex energy relationships, interdependencies, efficiency, and environmental enhancement opportunities of these practices and designs.
  - Develop tools and methods to identify and set energy sustainability goals and to verify that these goals are met.
  - Take a comprehensive approach, using life cycle studies or system analyses, to identify the costs, benefits, and trade offs of achieving these goals and to allow for more informed decision and policy making.

### *Analyze the Role of the State's Infrastructure Planning and Financing Activities in Promoting Smart Growth*

Additional analytical research is necessary for the state to examine its own appropriate role in encouraging efficient land use practices. The Energy Commission expects to examine this in the *2007 Integrated Energy Policy Report*.

The state took a major step toward smart growth with the passage of AB 857. This legislation established planning and development priorities for the state's infrastructure development and financing.

- ✓ The state should assess compliance with AB 857 and provide an assessment of successes and barriers to action.

With the passage of Propositions 1B—E and 84 (*Highway Safety, Traffic Reduction, Air Quality, and Port Security; Housing and Emergency Shelter Trust Fund Act of 2006; Kindergarten-University Public Education Facilities; Disaster Preparedness and Flood Prevention;* and *Supply. Flood Control. Natural Resource Protection. Park Improvements. Bonds. Initiative Statute,* respectively), the state will be able to make a significant impact in addressing deficiencies in and planning for the future of California's transportation, education, shelter, flood and "green" infrastructure.

The investment of public funds must support land use that avoids or mitigates increased energy usage and greenhouse gas emissions. Other states, such as Maryland and New Jersey, have implemented programs that direct state infrastructure funds toward projects that incorporate good land use practices and withhold it from projects that do not. The Energy Commission believes that California should explore adopting a similar program.

- ✓ The state should develop criteria for smart growth development and prioritize infrastructure funding toward development that meets those criteria.

# APPENDIX: ACRONYMS IN THE 2006 INTEGRATED ENERGY POLICY REPORT UPDATE

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|---|---|---|
| APA | — | American Planning Association |
| BLM | — | Bureau of Land Management |
| California ISO | — | California Independent System Operator |
| CACP | — | Clean Air Climate Protection |
| CAPM | — | Capital Asset Pricing Model |
| CEC | — | California Energy Commission |
| CEII | — | Community Energy Independence Initiative |
| CEQA | — | California Environmental Quality Act |
| CHP | — | Combined Heat and Power |
| CMUA | — | California Municipal Utilities Association |
| $CO_2$ | — | Carbon Dioxide |
| COG | — | Council of Government |
| CPCN | — | Certificate of Public Convenience and Necessity |
| CPUC | — | California Public Utilities Commission |
| CSRTP-2006 | — | California Independent System Operator South Regional Transmission Process for 2006 |
| DG | — | Distributed Generation |
| DOE | — | Department of Energy |
| EE | — | Energy Efficiency |
| EEM | — | Energy Efficiency Mortgage |
| EESI | — | Environmental and Energy Study Institute |
| EGPR | — | Environmental Goals and Policy Report |
| EIR | — | Environmental Impact Report |
| EIS | — | Environmental Impact Statement |
| ESB | — | Energy Savings Bid program |
| ESP | — | Energy Service Provider |
| EU | — | European Union |
| FERC | — | Federal Energy Regulatory Commission |
| FHA | — | Federal Housing Administration |
| GHG | — | Greenhouse gas |
| GIS | — | Geographic Information System |
| GWh | — | Gigawatt hour |
| HEAT | — | Harmonized Emissions Analysis Tool |
| ICLEI | — | International Council for Local Environmental Initiatives |
| IID | — | Imperial Irrigation District |
| IOU | — | Investor-owned Utility |
| ITS | — | Intelligent Transportation Systems |
| kV | — | Kilovolt |
| kWh | — | Kilowatt hour |
| LADWP | — | Los Angeles Department of Water and Power |

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|---|---|---|
| LEED-ND | — | Leadership in Energy and Environmental Design for Neighborhood Development |
| LGC | — | Local Government Commission |
| LGEEP | — | Local Government Energy Efficiency Program |
| LGSEC | — | Local Government Sustainable Energy Coalition |
| LOLP | — | Loss of Load Probability |
| MMTCE | — | Million Metric Tons $CO_2$ Emissions |
| MPO | — | Metropolitan Planning Organization |
| MPR | — | Market Price Referent |
| MW | — | Megawatt |
| MWh | — | Megawatt hour |
| NEPA | — | National Environmental Policy Act |
| NYMEX | — | New York Mercantile Exchange |
| OPR | — | Governor's Office of Planning and Research |
| PG&E | — | Pacific Gas and Electric Company |
| PGC | — | Public Goods Charge |
| PIER | — | Public Interest Energy Research Program |
| PLACE3S | — | Planning for Community Energy, Economic, and Environmental Sustainability |
| POU | — | Publicly Owned Utility |
| PRG | — | Procurement Review Group |
| REC | — | Renewable Energy Certificate |
| RFO | — | Request for Offers |
| RGGI | — | Regional Greenhouse Gas Initiative |
| RMR | — | Reliability Must Run |
| RPS | — | Renewable Portfolio Standard |
| SACOG | — | Sacramento Area Council of Governments |
| SANDAG | — | San Diego Association of Governments |
| SCE | — | Southern California Edison Company |
| SDG&E | — | San Diego Gas and Electric Company |
| SDREO | — | San Diego Regional Energy Office |
| SEP | — | Supplemental Energy Payment |
| SLO | — | San Luis Obispo |
| SMUD | — | Sacramento Municipal Utility District |
| TOD | — | Time of Delivery |
| U.S. DOT | — | Unites States Department of Transportation |
| USGBC | — | United States Green Building Council |
| VA | — | Veteran's Administration |
| VMT | — | Vehicle Miles Traveled |
| WEST | — | Water Energy Sustainability Tool |