CALIFORNIA ENERGY COMMISSION

2006 INTEGRATED ENERGY POLICY REPORT UPDATE

COMMITTEE DRAFT REPORT

November 2006
CEC-100-2006-001-CTD

Arnold Schwarzenegger, *Governor*

CALIFORNIA ENERGY COMMISSION

2007 INTEGRATED ENERGY POLICY REPORT COMMITTEE

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DISCLAIMER

This report was prepared by the California Energy Commission's 2006–2007 Integrated Energy Policy Report Committee as part of the 2007 Integrated Energy Policy Report proceeding, Docket # 06-IEP-1. The report will be discussed at a public workshop on December 7, 2006. The views and recommendations contained in this document are not official policy of the Energy Commission until the report is adopted.

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 to achieve 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 planning.

PREFACE

As required by Senate Bill 1389 (Bowen and Sher), Chapter 568, Statutes of 2002, the California Energy Commission conducts "assessments and forecasts of all aspects of energy industry supply, production, transportation, delivery and distribution, demand, and prices." The Energy Commission uses these assessments and forecasts to develop energy policies that conserve resources, protect the environment, ensure energy reliability, enhance the state's economy, and protect public health and safety (Public 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, again as required by SB 1389, 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 (Public Resources Code § 25302[d]). The *2006 Integrated Energy Policy Report Update* fulfills the update requirement for 2006.

As in previous proceedings, the 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.

ACKNOWLEDGEMENTS

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EXECUTIVE SUMMARY

In the *2005 Integrated Energy Policy Report*, adopted on November 12, 2005, the California Energy Commission (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.

Building on the analysis and recommendations contained in that report, the Integrated Energy Policy Report Committee (Committee) released a notice on May 1, 2006, for a hearing on May 12, 2006, to receive comments on a proposed scope for the 2007 Integrated Energy Policy Report proceeding. In the hearing notice, the Committee 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 on the Integrated Energy Policy Report process.

At the May 12, 2006 public 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.

The purpose of the *2006 Integrated Energy Policy Report Update* is to assess progress made on the critical elements of the 2007 general topics. As an interim part of the 2007 Integrated Energy Policy Report proceeding, the *Integrated Energy Policy Report Update* reviews the status of selected elements recommended in the *2005 Integrated Energy Policy Report* and/or introduces topics that deserve more attention because of their potential to help the state address key energy goals.

The *2006 Integrated Energy Policy Report Update* focuses on two topics: 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 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. However, 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.

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

Midcourse Review of the Renewable Portfolio Standard

California has made only minimal progress to date in meeting the Renewable Portfolio Standard goals, and the Renewable Portfolio Standard program faces a number of challenges. 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 one percent per year as required under the statute. 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.

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 4,095 megawatts of renewable capacity. However, of those renewable contracts only 242 megawatts are on line 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 generation 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, including setting individual targets and dates. As a result, the progress of the state's publicly owned utilities in achieving 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 2 percentage points per year between now and 2010.

Barriers to Achieving Renewable Portfolio Standard Goals

Five primary barriers stand in the way of achieving the state's Renewable Portfolio Standard goals:

- Inadequate transmission infrastructure to connect remotely located renewable resources.
- Complexity and lack of transparency in the Renewable Portfolio Standard program for investor-owned utilities.
- Insufficient attention to the real possibility for contract failure and delay.
- Uncertainty regarding the financeability of supplemental energy payment awards.
- Lack of progress in repowering aging wind facilities.

One of the primary difficulties with the Renewable Portfolio Standard program is the lack of adequate transmission to access important renewable resources in Tehachapi and the Imperial Valley that could help meet Renewable Portfolio Standard goals. 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.

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. In addition, the process for setting the benchmark price for electricity 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. The California Public Utilities Commission has deferred to the business judgment of investor-owned utilities in many of the details of conducting Renewable Portfolio Standard solicitations, and must therefore hold them accountable for meeting Renewable Portfolio Standard targets.

Utility procurement strategies have not yet seriously factored in the risk of contract failure, creating additional uncertainty about the attainment of Renewable Portfolio Standard goals. Many renewable projects with Renewable Portfolio Standard contracts have been delayed, and a number of them have been cancelled. In addition, there is uncertainty whether several of the largest Renewable Portfolio Standard contracts will come to fruition because they involve technologies not yet commercially proven. Also, some renewable developers may be unwilling to do business in California because of perceived regulatory risk and difficulties in obtaining project financing.

Many stakeholders have raised concerns that supplemental energy payment awards under the current program structure do not represent a financeable revenue stream, making it impossible for projects that require public funds to receive the financing needed to move forward.

Finally, over the last several years utilities have made little, if any, 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 detail in the *2004 Integrated Energy Policy Report Update* and the *2005 Integrated Energy Policy Report* and is revisited here because of this lack of progress.

Recommendations to Achieve Near-Term Renewable Portfolio Standard Goals

To get the Renewable Portfolio Standard back on track and ensure achievement of the 20 percent by 2010 goal, the state needs to address these issues quickly. Although stakeholders acknowledge that problems exist with the Renewable Portfolio Standard structure, most parties agree that the state should not make wholesale changes to the program structure. This report therefore reluctantly recommends making no major changes to this structure, 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 Renewable Portfolio Standard goals.

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

- The state should enforce penalties for investor-owned utility non-compliance with Renewable Portfolio Standard goals consistent with Decision 06-05-039.
- 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, and 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. The market price referent calculation should more explicitly recognize the important value of renewable resources as a hedge against future natural gas price volatility.

- Investor-owned utilities should be required either to accept all Renewable Portfolio Standard offers under the market price referent or document why such offers were not accepted.
- The state should also evaluate the ramifications of providing a higher rate of return for renewable energy facilities to make them more financially attractive.

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 California Independent System Operator and the California Public Utilities Commission should consider ways to compel Southern California Edison to meet the 2010 schedule in the California Independent System Operator Plan of Service for full build-out of the Tehachapi region or allow other transmission developers to step in and complete transmission projects.
- 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 **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 above 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.
- The state should adopt project milestones consistent with those required for supplemental energy payments applications and require the investor-owned utilities to conduct comprehensive reporting on milestones and status.
- The Energy Commission should provide project assistance for renewable developers consistent with the "Green Team" approach established during the electricity crisis.
- Further analysis should be undertaken on altering the supplemental energy payment structure to make awards financeable.

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.

Addressing Long-Term Renewable Portfolio Standard Goals

The recommendations in this report are intended to address problems with the Renewable Portfolio Standard in the near term. However, other issues will affect the ability of California to meet its long-term Renewable Portfolio Standard goals of 33 percent renewable by 2020, as recommended by the Energy Commission, the California Public Utilities Commission, and Governor Schwarzenegger. This increased goal is essential to the success of the state's efforts to reduce greenhouse gas emissions and to achieve the other benefits associated with the use of renewable energy.

California must continue its pace of renewable development toward the 33 percent goal. This report therefore also identifies issues that need additional study and analysis over the next year as part of the *2007 Integrated Energy Policy Report*.

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 (Nuñez), Chapter 488, Statutes of 2006.
- Alternative structures to meet 2020 Renewable Portfolio Standard goals, including whether a system benefit charge for renewables or feed-in tariffs are preferable approaches to spur additional renewable development.
- Changing or eliminating the market price referent/supplemental energy payment award structure to address concerns about the complexity and transparency of the Renewable Portfolio Standard Program and the financeability of these awards. Some of these changes may be desirable in the pre-2010 period.

There is much work to be done to ensure that California is able to take advantage of the unique benefits that renewable resources bring to the state. The Energy Commission looks forward to an active discussion of these issues in the *2007 Integrated Energy Policy Report*.

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 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 5.5 million metric tons CO_2 equivalent by 2010 and 18 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 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 are rarely considered in planning uses for land parcels.

Zoning ordinances divide cities into districts and apply particular regulations in each district. The ordinances must be consistent with the general plan. The planning process may require an environmental review at various points. However, "the environment" in this case does not mean "energy."

Land use planning is done at the local and regional level, the latter through voluntary intergovernmental associations called councils of government and metropolitan planning organizations. Energy providers are typically not players in land use planning.

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 Assembly Bill 857's planning priorities. 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 are some of the local governments that have taken significant action in furthering smart growth.

Further Action Is Needed to Integrate Land Use Planning and Energy

In spite of the exemplary actions underway by some local governments, much more can and should be done to couple land use and energy. Smart growth can play a central role in meeting many of the state's energy goals. First, however, the definition of smart growth must be expanded to include all energy elements. 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 additional actions that will help to realize the benefits of integrating land use and energy.

Broaden the Definition of Smart Growth to Include All Energy Saving Strategies

Based on a review of the literature and from comments received at the Land Use and Energy workshop, the Energy Commission believes that the definition of smart growth must be broadened beyond the current focus on vehicle miles traveled to include distributed generation; the on-site use of renewable energy; orientation of residences in relation to the sun; enhanced shading; and the use of roofs, building materials, and home appliances that minimize energy use. This broader definition would provide additional strategies that would help the state meet its Renewable Portfolio Standard goals, reduce its energy demands and greenhouse gas emissions, and help negate the effects of global climate change.

Promote Smart Growth as an Integral Component of Reducing Greenhouse Gas Emissions

Employing smart growth principles in the state's land use planning processes is a key strategy for reaching California's climate change goals. This strategy will require a comprehensive examination on a local level of every aspect of energy: resources, energy, efficiency, renewables, transmission and transmission infrastructure, distributed generation, and transportation energy use. The strategy involves a host of tactics, including a concerted effort by local governments to take up the greenhouse gas reduction challenge, support by state government of local government efforts and partnership efforts, and development and deployment of new planning tools and new research projects related to sustainable planning.

Require Local Governments to Prepare Greenhouse Gas Reduction Plans

Local governments will be key to achieving the aggressive GHG emission reductions contained in the smart land use and energy efficiency measures identified in the Climate

Action Team report. Many local governments have already taken up the challenge: over 40 California cities have signed the U.S. Mayors Climate Protection Agreement and committed their cities to meet or beat the U.S. emissions reduction target in the Kyoto Protocol. While the Energy Commission supports keeping land-use decisions at the local government level, not at the state level, these decisions should be more explicitly guided by state policy goals. The Energy Commission recommends the following actions:

- The state should collaboratively develop legislation that would require local governments to develop greenhouse gas reduction plans as part of state efforts to achieve the goals of Assembly Bill 32.
- Local governments should make energy accounting a key element of general plans, with support as needed and available from the state.

Integrate Utilities in Land Use Decisions

Through their energy efficiency programs and other efforts, the state's major investor-owned utilities are forming partnerships with cities and other entities to incorporate sustainability concepts in communities. Qualifying 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. Municipal utilities also promote energy efficiency and, because they are owned by the communities, often have greater visibility and integration in local planning.

The Energy Commission recommends that:

- State agencies should double their efforts to comply with Assembly Bill 857 and provide an assessment of successes and barriers to action.
- The Energy Commission should develop and publish case studies and best practices guides that describe the successes of local government smart growth efforts, as well as additional outreach materials to promote sustainable development.
- The Energy Commission should invite stakeholders to participate in an ongoing land use/energy working group that would convene on a regular basis to discuss land use and energy issues in general and local greenhouse gas reduction plans in particular.
- The Local Government Council should continue 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
- The state's utilities should continue to partner with local governments to establish and incentivize sustainable developments in their service territories.

- The state should identify and promote funding sources to reward local governments to engage in smart growth planning practices.

Conduct Research on 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*." This roadmap identified areas of needed research, focusing on the connection between municipal governments and electricity use. As noted at September's Land Use and Energy workshop, research is needed 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.

CHAPTER 1: INTRODUCTION

Developing the 2006 Integrated Energy Policy Report Update

In the *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.

Building on the analysis conducted in the 2005 Integrated Energy Policy Report proceeding and on the resulting recommendations, the Integrated Energy Policy Report Committee (Committee) released on May 1, 2006, a notice for a hearing to receive comments on a proposed scope for the 2007 Integrated Energy Policy Report proceeding. In the hearing notice, the Committee 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 on 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* is to assess the progress made on the critical elements of the 2007 general topics. As an interim part of the 2007 Integrated Energy Policy Report proceeding, the *2006 Integrated Energy Policy Report Update* reviews the status of selected elements recommended in the *2005 Integrated Energy Policy Report* and/or introduces topics that deserve more attention because of their potential to help the state address key energy goals.

The *2006 Integrated Energy Policy Report Update* focuses on two topics: 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 an investigation of energy saving opportunities related to "sustainable" land use planning, also called "smart growth."

The Committee will hold 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 will prepare a final report for Energy Commission consideration for adoption in January 2007. 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 Renewable Portfolio Standard 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 achieving the RPS, such as a lack of transparency, overly complex rules, and inconsistent application among retail sellers. Intense fact finding and meetings with stakeholder organizations formed the foundation of this midcourse review to update RPS progress and resulted in recommendations to escalate meeting RPS goals.

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 Committee believes that this topic serves as the nexus for developing distributed renewable generation and efficient transportation in communities. 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 goals.

Organization of the Report

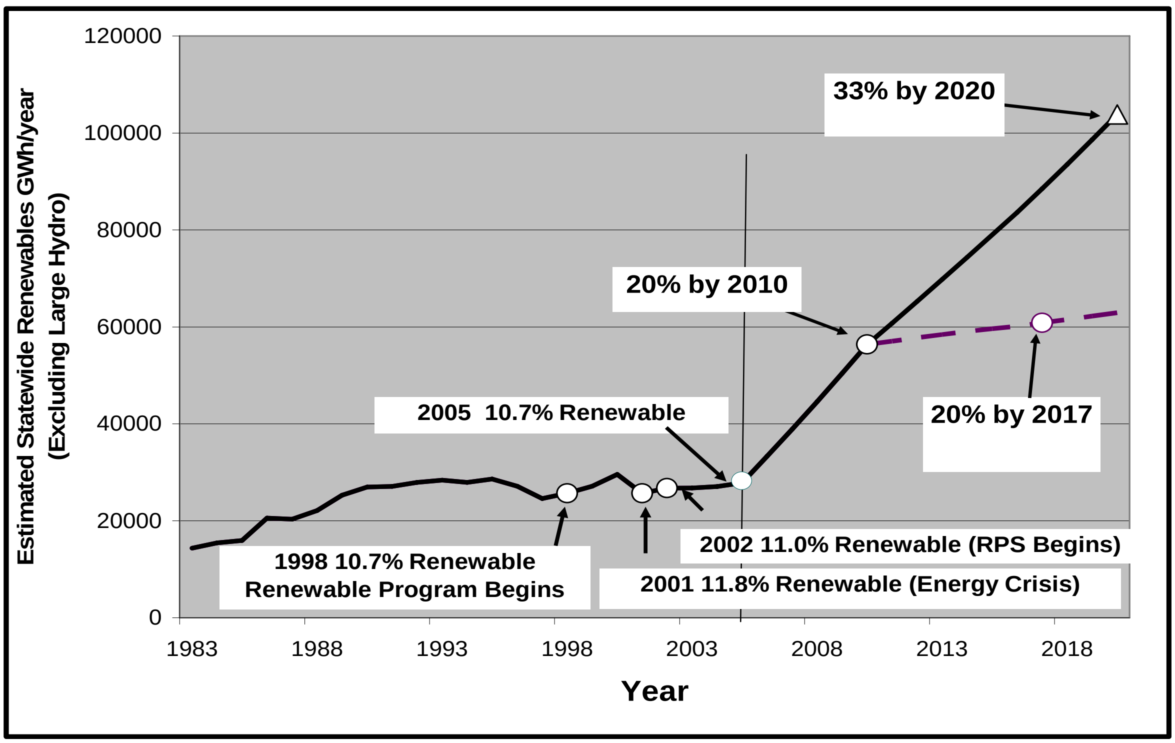
The *2006 Integrated Energy Policy Report Update* devotes one chapter to each topic and explores each in depth. Both chapters provide a historical perspective, a review of current status, and a discussion of barriers that jeopardize progress. They also make recommendations for their respective topics: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

CHAPTER 2: MIDCOURSE REVIEW OF THE RENEWABLE PORTFOLIO STANDARD

Introduction

The *2005 Integrated Energy Policy Report* concluded that statewide renewable procurement is not occurring at a pace that will reach California's Renewable Portfolio Standard (RPS) goals by 2010 and, as a result, the RPS process is in need of midcourse review and correction. As shown in Figure 1, halfway between the 2002 legislative enactment and the 2010 target date, the state has made little progress toward increasing the percentage of renewable energy in the system mix since the 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. [1]

[1] 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.

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 investor-owned utilities (IOUs), community choice aggregators, and energy service providers (ESPs), to increase the portion of electricity from retail sales by at least one percent per year toward a goal of 20 percent by 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.[2] 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.[3]

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 4,100 megawatts (MW) of renewable capacity, only about 240 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).[4] However, in October 2006, the CPUC adopted Decision 06-10-050 which states, "Nothing presented here

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

[3] Ibid.

[4] 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."

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 is actual deliveries."[5] 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 addressed. These include:

- 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.
- Lack of progress in planning, permitting, and cost allocation for transmission upgrades and additions necessary to access remote renewable resources.
- Inadequate consideration of contract failure and project delays that jeopardize attainment of the 2010 RPS goals.
- Financeability of supplemental energy payments (SEPs).
- 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 Committee and CPUC Commissioner John Bohn held a workshop on the RPS midcourse review. Topics for 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,

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

consistent with similar market estimates used for energy efficiency and for non-renewable procurement processes?

- 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 (CAISO) interconnection queue, and CAISO 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: California Not on Track to Meet 20 Percent by 2010

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.[6]

[6] 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.

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.

As shown in Table 1, San Diego Gas and Electric (SDG&E) has made the most progress in increasing its renewable purchases — moving from one 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 .2 percent between 2002 and 2005, making little progress in the last three years despite the proximity of the Tehachapi Wind Resource Area and various mechanisms that allow SCE to develop the needed transmission.

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 2,669 and 4,095 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.[7] The amount of renewable capacity under contract therefore might appear to represent significant progress. However, contracts for 154 MW have been canceled, at least 10 are not expected to deliver until 2010 or later, and at least 22 have been delayed. In addition, a significant share of the contracted capacity is from 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.[8] 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 energy expected from contracts that have been signed as of September 2006, is between 6,331gigawatt hours (GWh) and 11,103 GWh per year (less transmission and distribution losses).[9] 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 952 GWh per year will be produced from facilities that are on line at the end of September, 2006.[10] To meet the RPS goal of 20 percent by 2010, the IOUs, collectively, will need to add between 1,337 GWh and 6,624 GWh annually over the next three years. Assuming an average 50 percent capacity factor, the additional energy needs translate to between 305 MW and 1,510 MW of additional renewable generating capacity by 2010.[11]

Investor-Owned Utility 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.”[12] 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

[7] 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.

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

[9] 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.

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

[11] 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 September 2006 but not on line in 2005 (7,185 to 12,030 GWhs), and assuming a 50 percent average capacity factor for the 2010 renewable resource mix.

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

be a problem."[13] 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."[14] 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.

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.[15] In April 2005, SCE stated "We are on track to reach California's renewable power standard of 20% for utilities well ahead of schedule."[16] However, by August 2005, SCE had tempered its claims in the press somewhat, 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."[17]

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 [CEC], absolutely."[18] 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."[19]

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."[20]

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[13] *The Bakersfield Californian*, July 13, 2004, "Utilities On Board With Renewables."

[14] 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.

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

[16] "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.

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

[18] 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.*

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

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

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."[21] 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."[22]

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."[23] 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."[24]

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."[25]

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[21] 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*.

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

[23] "Sempra Generating New Energy," The San Diego Union-Tribune, June 18, 2006.

[24] Pedro Pizarro, transcript of the July 6, 2006 Integrated Energy Policy Report Committee workshop, *Midcourse Review of the Renewables Portfolio Standard Process*.

[25] 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*.

Progress Made by Publicly Owned Utilities

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.[26]

The RPS legislation initially made each POU responsible for "implementing and enforcing a renewable portfolio standard that recognizes the intent of the Legislature to encourage renewable resources, while taking into consideration the effect of the standard on rates, reliability, and financial resources and the goal of environmental improvement."[27] However, POUs are not bound to the initial goal established for IOUs, ESPs and CCAs 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,[28] 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,[29] while LADWP has committed to reaching 20 percent by 2010 and is aggressively pursuing that goal.[30]

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[26] 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.

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

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

[29] 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.

[30] 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.

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.[31]

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 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 nine to eleven percent, and LADWP increased from 1.8 to 2.4 percent, while IID decreased renewables from 12.0 to 7.6 percent.[32]

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 from Wyoming, while Silicon Valley Power announced the purchase of 105 MW of wind power from a new wind project in Washington.[33] 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 two 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

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

[32] California Energy Commission, data reported in Annual Report to the California Energy Commission: Power Source Disclosure Program, March 2006, pursuant to AB 1305.

[33] 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.

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

Publicly Owned Utility Goals for Greenhouse Gas Reduction

In the first half of 2006, the California Municipal Utilities Association (CMUA) developed the *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, including LADWP, SMUD, and Santa Clara have adopted these principles:[34]

- 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.

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

- 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:
    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 towards 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.[35]

Barriers to Meeting Renewable Goals

Five main barriers stand in the way of meeting the state’s 2010 RPS goals. First, transmission access for renewables is not available. 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 take advantage of these promising resources, further jeopardizing the RPS goals.

Second, there is the lack of transparency in the bidding, ranking, and contracting processes used to select renewable projects. Bidders need better information 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.

Third, the reliance on contracts, rather than energy deliveries, as a measure of progress toward the RPS puts the RPS 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.

Fourth, 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.

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.

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

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. Disagreements persist on which are the best configurations for additional segments of transmission in the Tehachapi area to allow for a full build-out of wind resources. Cost allocation issues for renewable transmission also continue to plague renewable transmission projects. Unless these challenges are met head on, 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 somewhat in overcoming 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 CAISO control area. Despite this relaxation in delivery requirements, unless sufficient transmission infrastructure is developed to connect renewable resources into the CAISO bulk transmission system and to the transmission systems of municipal utilities, these renewable resources will remain inaccessible to the state's electric utilities.[36] 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

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

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 status on these projects.

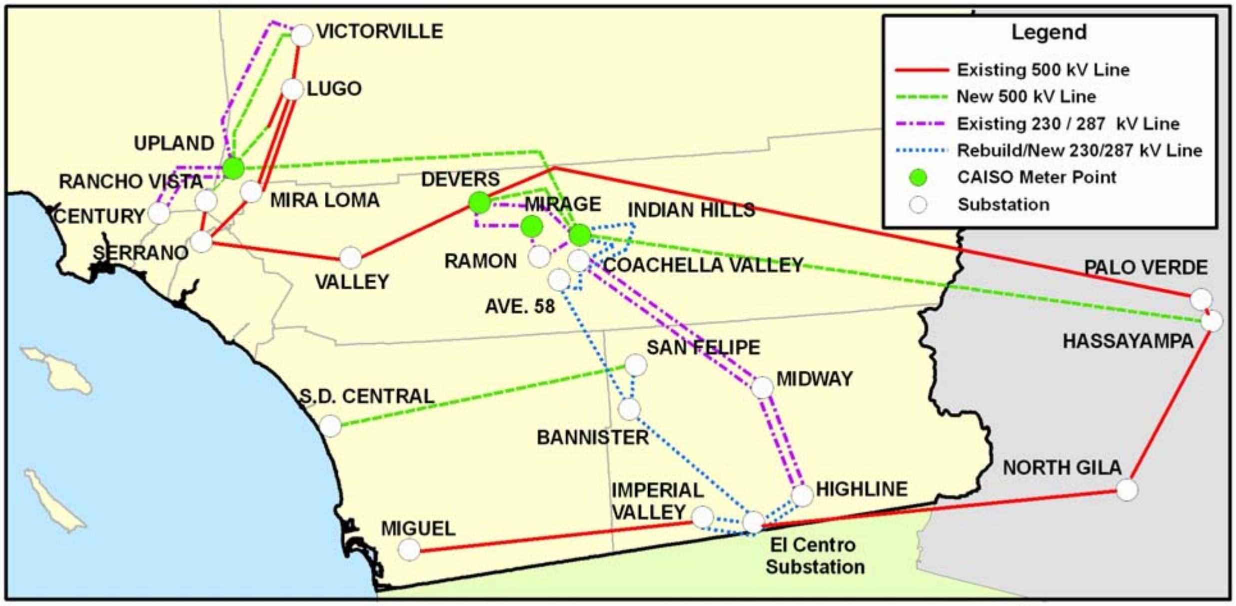
Sunrise Powerlink Project

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 the state's RPS goals, ensure system reliability, or reduce reliability must-run (RMR) and congestion costs.

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 (PEA). 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 (MOA) 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 MOA 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 MOA on June 21, 2006.

Figure 2. Sunrise Powerlink Project

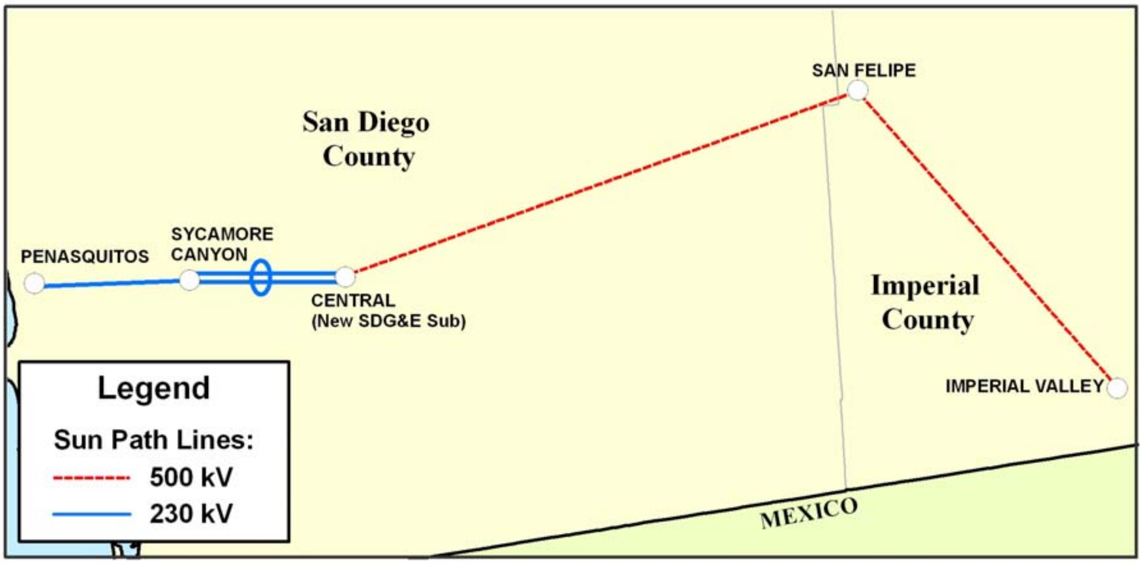


The CAISO Board of Governors voted unanimously to approve the Sunpath Project (the combined Sunrise Powerlink/Green Path Project – Southwest project, see Figure 3) at its August 3, 2006, board meeting.[37]

SDG&E then filed an amended application, including the PEA, to the CPUC on August 4, 2006 (A.06-08-010). The application was deemed complete on September 8, 2006.[38] 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.[39] A recent scoping order for the Sunrise project calls for an analysis of the full range of alternatives, including incremental energy efficiency and integrated wire and non-wire strategies.[40] This scoping order identifies a projected decision date for the CPCN of January 2008.

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

Figure 3. Sunpath Project



Antelope Transmission Project (Tehachapi Transmission Plan, Phase I)

The Antelope Transmission Project (see Figure 4), 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.

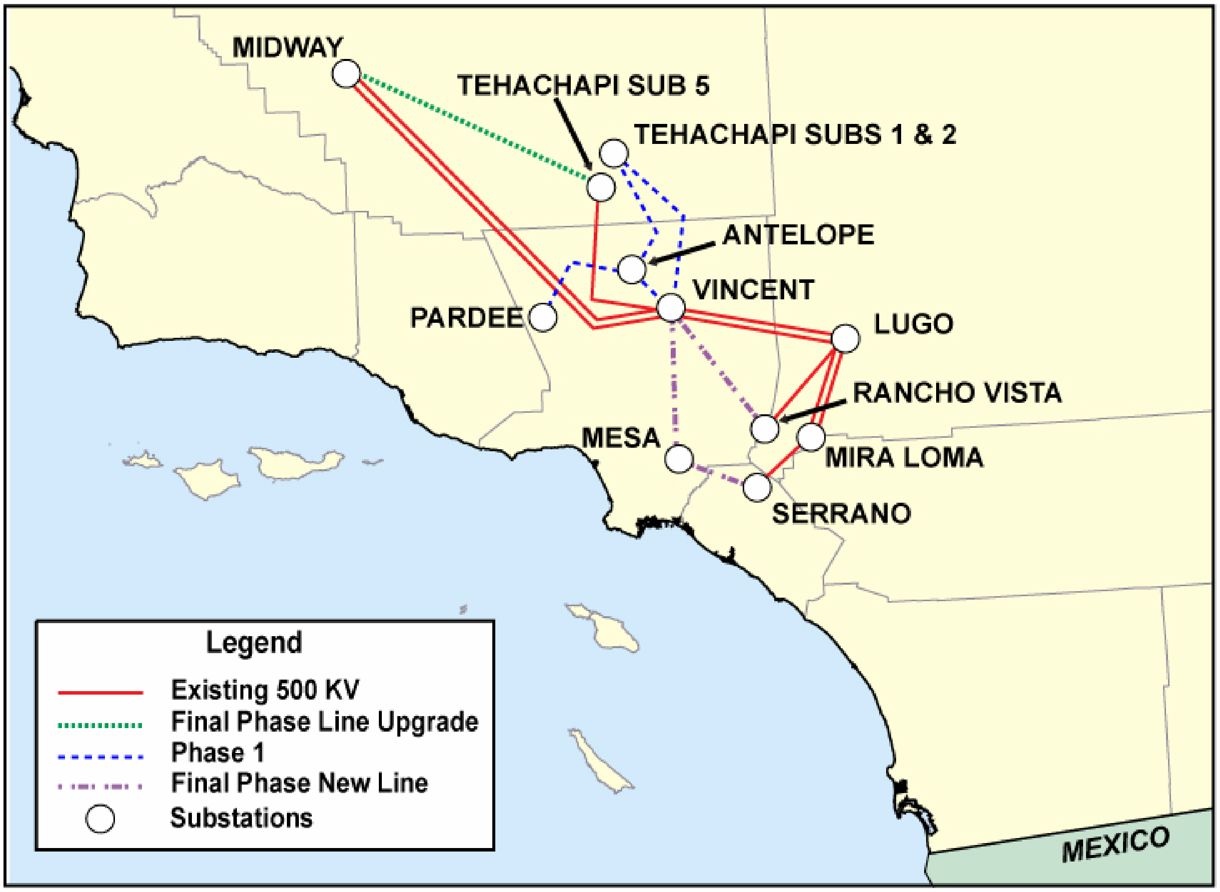
The CAISO unanimously approved the project on July 29, 2004.[41] Phase 1 consists of three segments: Segment 1 is a new 500-kV, 25.6-mile transmission line from the existing Antelope Substation to the existing Pardee Substation, initially energized at 220 kV. The project, which would replace an existing 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

[41] See Web site http://www.caiso.com/docs/09003a6080/32/43/09003a6080324395.pdf.

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.[42]

Figure 4. Tehachapi Project



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.[43] The CPUC held informational workshops and public participation hearings on October 11 and 12, 2006.

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

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

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.[44]

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 Los Angeles Department of Water and Power (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.

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 status.

Continuing Problems in Transmission Permitting and Planning

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

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

> 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 the all three phases of Tehachapi continue to be the subject of ongoing debate, as shown in Table 2. On September 19, 2006, SCE estimated the on-line date for 700 MW of wind in Segment 1 as 2009, at a presentation to the CAISO South Regional Transmission Process for 2006 (CSTRP-2006), with another 2,200 MW to be on line by 2012. This included Substation 1 at Antelope and Substation 5. By October 24, 2006, SCE's estimate was that 2,500 MW would be on line in 2010 and would include the 500-kV Substation 5.

The CAISO staff is expected to present its analysis of the entire Tehachapi project to the Board of Governors on December 6, 2006, 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.

Table 2. Estimated On Line Dates for Tehachapi

	CPUC (8/23/2006 Workshop)	SCE (9/19/2006 at CSTRP Workshop)	SCE (10/24/2006)
Phase 1, Segment 1	1/2009	2009 (700 MW)	12/1/2008
Phase 1, Segment 2 & 3	5/2009		6/1/2009
Phase 2, Segments 4–8	12/2010	2012 (2,200 MW)	6/1/2011
Vincent-Mira Loma Upgrades[45]		2013	6/1/2013
Phase 3, Segments 9–12[46]	6/2012	2015 (4,500 MW)	12/1/2015

Federal Transmission Corridor Planning and Permitting

As noted in the *2005 Integrated Energy Policy Report*, changes in the federal landscape under the *Energy Policy Act of 2005* require the Department of Energy (DOE) to designate this year transmission corridors of national significance.[47] Under this same law FERC can now authorize construction of a transmission line of national significance if an 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.

In recent comments to DOE on their *National Electric Transmission Study* and possible designation of national interest electric transmission corridors, the Energy Commission,

[45] 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 SCE 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.
[46] Per Presentation by Tom Flynn, 8/23/2006 California Public Utilities Commission Workshop
[47] Section 1221 of the Federal Power Act of 2005.

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 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 (PEIS) 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 PEIS. 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."[48]

As noted in the *2005 Integrated Energy Policy Report*, the Federal Energy Regulatory Commission (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 CAISO participants, the pivotal segment which would link major concentrations of renewable energy resources to the CAISO-controlled grid was not allowed rolled-in rate treatment.

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

As a result, the Energy Commission reiterated its 2003 recommendation for changes to the CAISO tariff to recognize a third category of transmission facilities that would encourage renewable transmission development. [49]

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 renewable energy resources.[50] 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.[51]

Over the last several months, the CAISO 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 CAISO 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.[52] The CAISO 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.[53] The CAISO 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 CAISO proposed and has refined a general framework for new evaluation criteria for certain transmission projects that are not considered "network upgrade" facilities. The CAISO has also proposed alternative treatment for the costs associated with this type of transmission project.

On October 19, 2006, the CAISO 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 CAISO 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

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

[50] 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.

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

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

[53] Ibid, p. 10.

connect to the lines in the future. If FERC grants the declaratory order, the CAISO will conduct a stakeholder process to obtain additional input and then file detailed tariff language with FERC.

The Energy Commission strongly supports the CAISO'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, to foreclose the innovation needed to bring new renewable resources to the market using newly constructed or upgraded transmission infrastructure to address existing constraints.

Lack of Transparency

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 asked for and 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."[54]

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 ensure that IOUs did not arbitrarily select projects without taking into consideration the full range of benefits provided by renewable generators. The "least-cost" element helps minimize cost impacts on utility ratepayers of procuring renewable

[54] 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.

energy. The CPUC defines "best fit" as "the renewable resources that best meet the utility's energy, capacity, ancillary service, and local reliability needs."[55]

Each IOU has its own distinct least-cost, best-fit approach. As noted in the *2005 Integrated Energy Policy Report*, descriptions provided by the IOUs on their least-cost, best-fit criteria suffer considerable murkiness and 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 impossible for policy makers to determine whether IOUs are selecting projects that are truly least-cost and best aligned with the state's policy to provide long-term benefits to the system.

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 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 have yet provided the necessary information four months and six months, respectively, after submitting contract advice letters to the CPUC.

In addition, the process is one-sided: each IOU, as a monopoly buyer within its territory, has access to a great deal of information — such as the bids of all sellers — that is not available to all sellers. Because IOUs can construct their own RPS generation facilities, they have detailed information about market price and terms that is not available to their competitors. In a competitive market, multiple buyers would reduce this inequity. 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."[56]

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

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[55] 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.

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

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 will hold a workshop in late November 2006 to discuss the reports and areas where further transparency may be needed.

In addition, Decision 06-06-066 on confidentiality[57] 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 "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.[58] 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 potentially higher costs of procuring renewable energy.

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[57] 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.

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

The method for determining the MPR is essentially a stand-alone engineering calculation of the future cost, in dollars per kWh, of electricity from a 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. 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

The use of natural gas forecasts in establishing the MPR is problematic. The best assumption about all forecasts for commodities as volatile as natural gas is that they will be wrong. The 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.

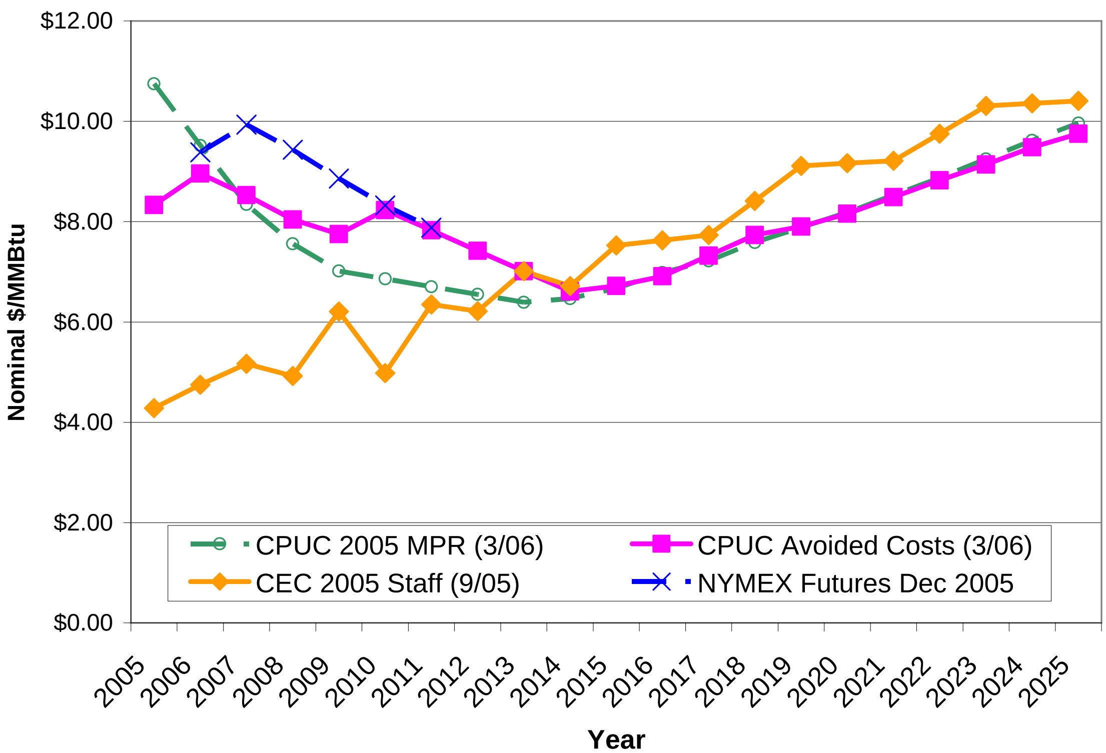
At a minimum, the state should use gas price forecasts for the MPR calculation that are consistent with forecasts used for procurement of other resources, including loading order resources. Otherwise renewable resources will be over- or under-valued, depending on the specific MPR methodology in vogue during each cycle, which will in turn distort pricing signals necessary to promote a competitive renewable industry in the long run. In addition, 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 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.

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 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 account for the value of renewable energy as a hedge. 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.

Figure 5. Comparison of Natural Gas Forecasts

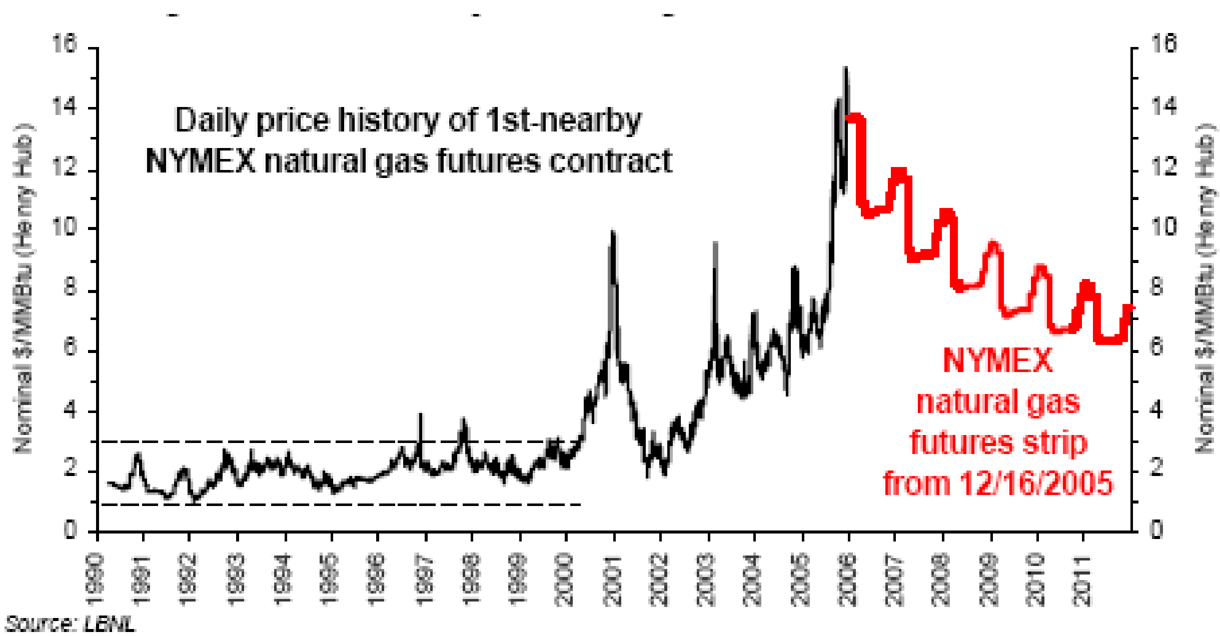


Source: Presentation by Richard McCann at 2006 Integrated Energy Policy Report Midcourse Review Committee workshop, August 22, 2006, *Comparison of Natural Gas Price Forecasts*

Natural gas prices fluctuate wildly and unpredictably over time. As shown in Figure 6, 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.

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.[59] 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.[60]

Figure 6. 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

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.[61]

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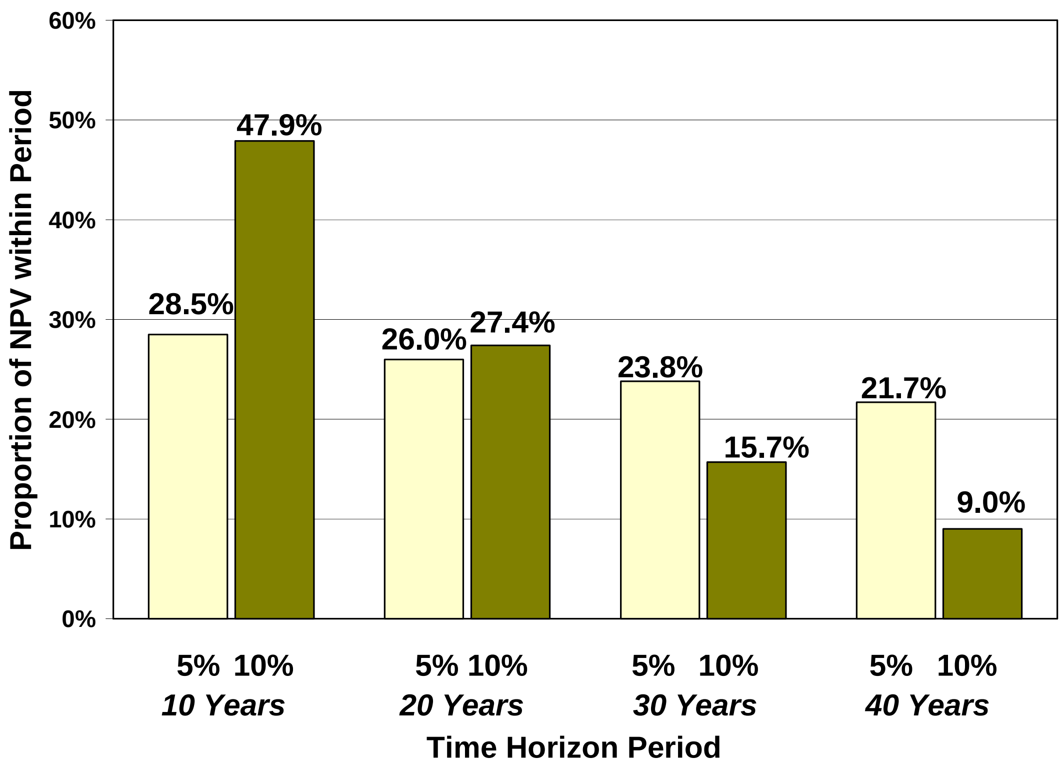
[59] Awerbuch, Shimon. *The True Cost of Fossil-Fired Electricity in the EU: A CAPM-based Approach,* January 2003, at http://www.london.edu/assets/documents/PDF/2.3.3.7.10_otm_seminar_true_cost_of_fossil_elecricity.pdf

[60] 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.

[61] 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.

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 7.

Figure 7. 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 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."[62]

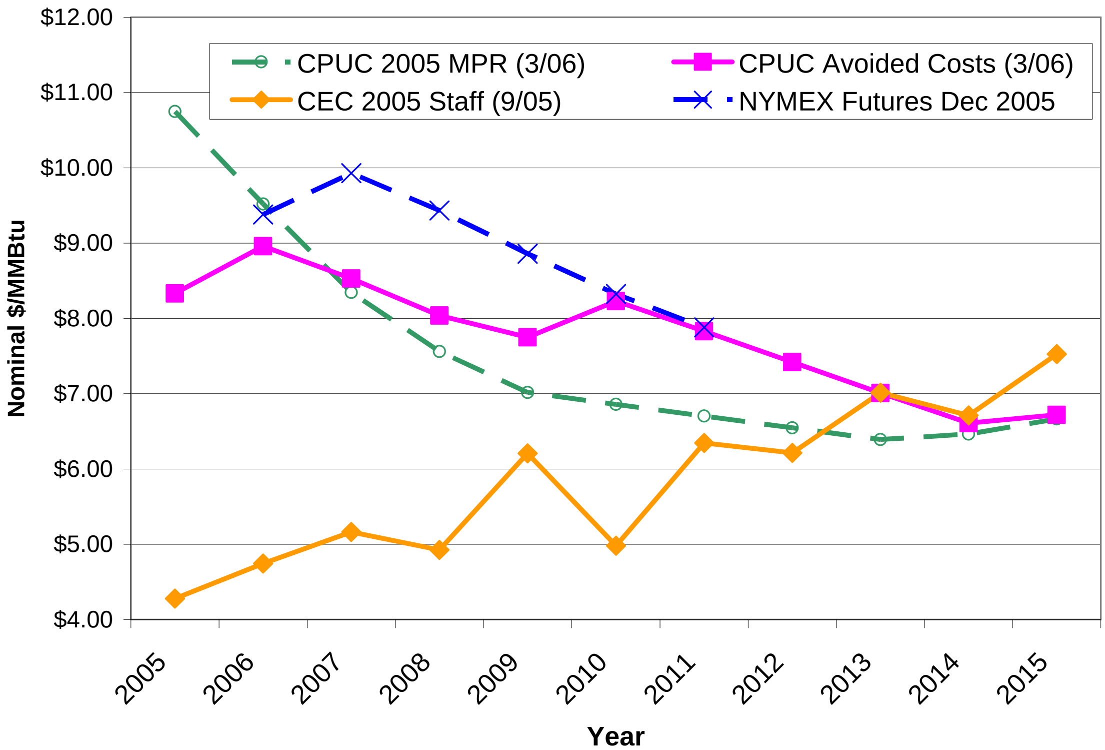
Figure 7 illustrates that, with a 10 percent discount rate, nearly half of the future value of a natural gas contract comes from the first 10 years, while only 28.5 percent of total value comes from the first 10 years with a 5 percent discount. Discount rates used by the IOUs in the 2005 RPS solicitation and the discount rate for MPR calculation are all close to 8

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

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.

Figure 8 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 8. Comparison of Natural Gas Forecasts, Detail 2005-2015



Time of Delivery Factors

A further complication in the calculation and application of MPRs is that each utility develops its own time of delivery 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.

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.[63] 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. 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 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* 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 one of its potential contracts. 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,

[63] California Energy Commission, Staff Presentation, August 22, *2007 Integrated Energy Policy Report Committee Workshop on Midcourse Review of the Renewables Portfolio Standard Process.*

> 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.[64]

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.[65] 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.[66] 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

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

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

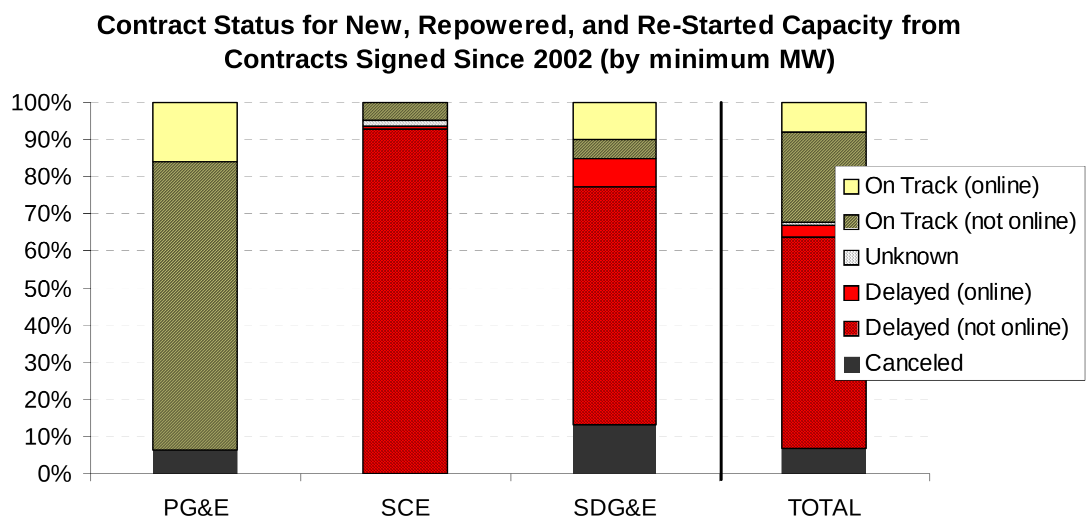
[66] *Building a Margin of Safety into Renewable Energy Procurements: A Review of Experience with Contract Failure.* CEC-300-2006-004. Prepared by Ryan Wiser, Ric O'Connell, Mark Bolinger, Robert Grace, and Ryan Pletka. January 2006. http://www.energy.ca.gov/2006publications/CEC-300-2006-004/CEC-300-2006-004.PDF

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.[67] 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 expecting or 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."[68]

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.

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*.

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

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[67] 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.

[68] 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.

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.

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.

Although these findings should be considered preliminary given the paucity of publicly available data and the early stage of the IOUs' contracting activity, one can reasonably expect the degree of contract failure – at least as indicated by project cancellations – to increase as projects move along their development paths.

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,[69] 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.

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

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

full term of the SEP award.[70] 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:

> 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 CEC'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. …

[70] 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.

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 (RRTF) 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 RRTF 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.

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.[71] In 2003, the California Wind Energy Association estimated that about 1,000 MW of aging wind turbines are candidates for repowering.[72] These older turbines are often located in some of the best wind resource areas and are already connected to the

[71] 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.

[72] 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*.

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 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.[73] Unfortunately, as shown in Table 4, little progress has occurred. Out of total RPS contracts for between 2,669 and 4,095 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.

[73] 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.

Recommendations to Assist in Reaching RPS Goals

Because the state is not on track to meet the 2010 goal, program improvements are needed. Recent legislation and decisions at the CPUC have increased the RPS expectations for POUs and ESPs as well as the IOUs. 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 goals. 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

√ Transmission infrastructure improvements are critical to accessing some of the most promising renewable resources in California. To meet the 20 percent by 2010 RPS goal, the Energy Commission recommends that the CPUC continue to do everything in its power 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 CAISO Board. The CAISO and CPUC should investigate what additional actions are necessary to either compel SCE to complete transmission additions consistent with that plan or to allow other transmission developers to step in and undertake transmission projects that SCE is unwilling to complete.

√ To resolve cost allocation issues for renewable transmission, the Energy Commission, CPUC and other state agencies, including the Department of Water Resources, and municipal utilities should all support the CAISO 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 CAISO can move forward with tariff amendments that will allow renewable transmission projects to move forward in a timely way.

Enforce Penalties for Non-Compliance

√ The state should enforce penalties for non-compliance with RPS goals, as articulated in CPUC Decision 06-05-039.

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.[74]

Penalties for failure to meet RPS goals have been clearly articulated by the CPUC: five cents per kilowatt hour for each kWh by which an IOU falls short of the target, with an overall cap of $25 million per year.[75] On May 25, 2006, the CPUC affirmed those penalties in Decision 06-05-039 and reiterated that the IOUs must meet the RPS goals or pay the penalties:[76]

- An IOU is subject to a non-compliance penalty of $0.05 per kilowatt-hour (kWh), with an overall cap at $25 million [per load-serving entity per year]. (page 25)
- The penalties provide incentives and clear consequences. (page 25)
- We encourage IOUs to redouble their efforts to make this program a success no later than 2010, rather than focus limited time and energy of parties and the Commission on modifying the program so IOUs do not later face the potential for penalties. (page 23)
- Importantly, IOUs understand that they are ultimately responsible for program success each year and by 2010. (page 21)

In its 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

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[74] 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.

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

[76] 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.

projects, and took any and all other actions that could reasonably have been expected to address, if not solve, the problem."[77]

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.[78]

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 will hold a workshop in late November 2006 at which IOUs will present their least-cost, best-fit methodologies to RPS stakeholders. This workshop could provide 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,[79] some inconsistency is apparent between the 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

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[77] Ibid.
[78] California Public Utilities Commission, Decision 06-10-019 in Rulemaking 06-02-012, October 5, 2006.
[79] 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.

more limited confidentiality for the RPS and will need to be modified to be consistent with the apparent intent of the decision.

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 recommends further analysis of altering the SEP award structure to make SEP awards financeable, including options such as granting SEPs to load-serving entities and making the SEP payment stream a contractual obligation.

Pay Supplemental Energy Payments to Load-Serving Entities

For projects above the MPR, a utility could 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.

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 payment risk from the project developer/owner to the load-serving entity, in doing so it largely resolves SEP financeability concerns. In addition, shifting SEP risk would presumably discourage utilities from signing above-MPR contracts that require SEPs.

Another potential advantage of this approach is that, unlike many of the other options previously discussed, it 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 RRTF collections dedicated to future SEP payments for projects currently under contract.

One drawback of this approach is that it could increase transaction costs since the Energy Commission would need to oversee this process to ensure that it is done properly. Another drawback is that the shift of SEP payment risk to the load-serving entity may be viewed as undesirable. If this risk transfer is believed to be inappropriate, then some form of escrow or prepayment approach (as discussed earlier) could potentially be worked out in conjunction with the load-serving entity, though this would also require that the Energy Commission pre-fund its SEP obligations. Alternatively, the CPUC could 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.

Because the RPS program currently requires SEP awards to be paid to facilities, this option would require new legislation.

Move Supplemental Energy Payment Funds to an Escrow Account

Stakeholders have suggested that RRTF 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 RRTF 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.

For example, 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.[80] 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.

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[80] 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.

Incorporate the Risk of Contract Failures and Delays

√ To address the risk of contract failures and delays, the Energy Commission recommends that utilities should procure a contract risk reserve margin of 30 percent above the amount needed for them to achieve 20 percent renewables by 2010. In addition, the state should more clearly indicate how it will apply penalties in case of contract failure.

√ In addition, to assure that renewable development contracts progress rapidly toward completion, the Energy Commission recommends that the state should adopt project milestones consistent with those required for SEP applications and require IOUs to provide comprehensive reporting on milestones and status to the CPUC.

√ 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 to 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 additional 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.

These steps begin to address the underlying concern of contract failure, but 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.[81] 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.

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.[82]

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.[83] 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. 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.[84] 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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[81] 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.

[82] 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

[83] 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.

[84] 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 RPS offers under the MPR, as long as such an approach does not increase program costs. This approach can help ramp up the rate of renewable development in a manner roughly analogous to the European feed-in tariffs, and should be implemented within the current program structure to help the state get on track to 20 percent by 2010.

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

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.[85] Today, Texas has more installed wind energy generation than California.[86]

The European Union has also made impressive progress in increasing its use of renewable resources, with wind energy in the EU–15 countries[87] 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),[88] or almost 400 terawatt-hours, was generated by renewable fuels

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[85] 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.

[86] 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*.

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

[88] 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.

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 in Germany, Denmark, and Spain, among others.[89] 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.[90]

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.

In addition, 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" [91] over the life of the contracts compared to the amount that would have been paid if the contracts were priced at the MPR. However, because of the data opaqueness which continues to plague the solicitation process, Energy Commission staff have been unable to verify such savings.

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[89] 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.

[90] 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.

[91] 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*, page 182-183.

Because the CPUC can require acceptance of streamlined bilateral contracts set at 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.

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, SB 1368 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 could 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.

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.[92]

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. 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.[93]

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[92] 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.

[93] 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.

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.

Assembly Bill 32 (Nuñez), Chapter 488, Statutes of 2006, requires the reduction of greenhouse gas emissions to 1990 levels in 2020, with the intent to continue reducing emissions beyond 2020.[94] 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.

In addition, under Senate Bill 1368 (Perata), Chapter 598, Statutes of 2006, California will begin requiring utilities to meet a greenhouse gas performance standard in 2007.[95] 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.[96]

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

[94] Assembly Bill 32 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.
[95] The California Public Utilities Commission is implementing Senate Bill 1368 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.
[96] 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 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.

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.[97]

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.[98] 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.[99] 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.[100]

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.[101] The California Climate Action Team's recent report to the Governor and

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[97] 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).

[98] 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.

[99] 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.

[100] 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.

[101] See, e.g., (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

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.[102]

Potential Structural Changes

This report focuses on near-term strategies needed to reach the 2010 RPS goal. However, to maintain the pace of renewable development in the long-term and reach the 33 percent by 2020 goal, the state needs to evaluate long-term solutions to barriers facing renewable development.

Capture Full Benefits of Renewables in the Market Price Referent

√ The Energy Commission recommends further analysis of the use 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.[103]

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

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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. See:

[102] "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

[103] Some studies have sought to quantify these possible benefits. See, e.g., Morris, G. 1999. "The Value of the Benefits of U.S. Biomass Power." NREL/SR-570-27541. Golden, Colorado: National Renewable Energy Laboratory.

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"[104] and that California utilities may 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 lessons learned from experiences 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).[105] RECs used to meet a state RPS program are excluded.[106] The model rule recommends allocating at least 25 percent of

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[104] Wiser, R. and Bolinger, M., "Balancing Cost and Risk: The Treatment of Renewable Energy in Western Utility Resource Plans," August, 2005.

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

[106] 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

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.[107] California plans to link its market-based GHG emission reduction strategy to RGGI (Executive Order S-20-06, October 18, 2006).

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.[108] 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

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

[108] 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,.

> 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.

Some of the sponsors of AB 32 criticized the Governor's Executive Order for moving too fast toward market-based compliance mechanisms, without due consideration and incorporation of concerns raised in AB 32. 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 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 CAISO [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 towards 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.[109]

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.

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 should consider what program structure to apply to the post–2010 RPS. One option is whether to authorize a system benefit charge for renewable energy for the 2011–2020 timeframe. The strengths and weaknesses of such an approach should be compared to other options such as reliance on 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.[110] 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 to 2020, and it is unclear what type of financial support, if any, will be available to help the state meet those goals.

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[109] 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.

[110] As provided in Assembly Bill 995 and Senate Bill 1194 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 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.

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.[111] 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."[112]

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,

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

[112] 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.

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.

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."[113]

Evaluate Potential Structural Changes to Supplemental Energy Payment Process

√ The Energy Commission recommends further analysis of the 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.[114] To avoid delay in

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[113] 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.

[114] 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.

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.
- 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.[115] 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.[116] 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.

[115] 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.

[116] 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.

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[117] — 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 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 (PTC).[118]

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.

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[117] 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.

[118] If structured properly – e.g., 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.

Abolishing the MPR/SEP structure may have other ancillary benefits as well.[119] 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 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.

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[119] 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.

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).[120]

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). This figure 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.[121]

Table 5. Comparison of Monthly Average Renewable Energy Certificate Prices

	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
Std Dev	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. The period of time for which REC 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).

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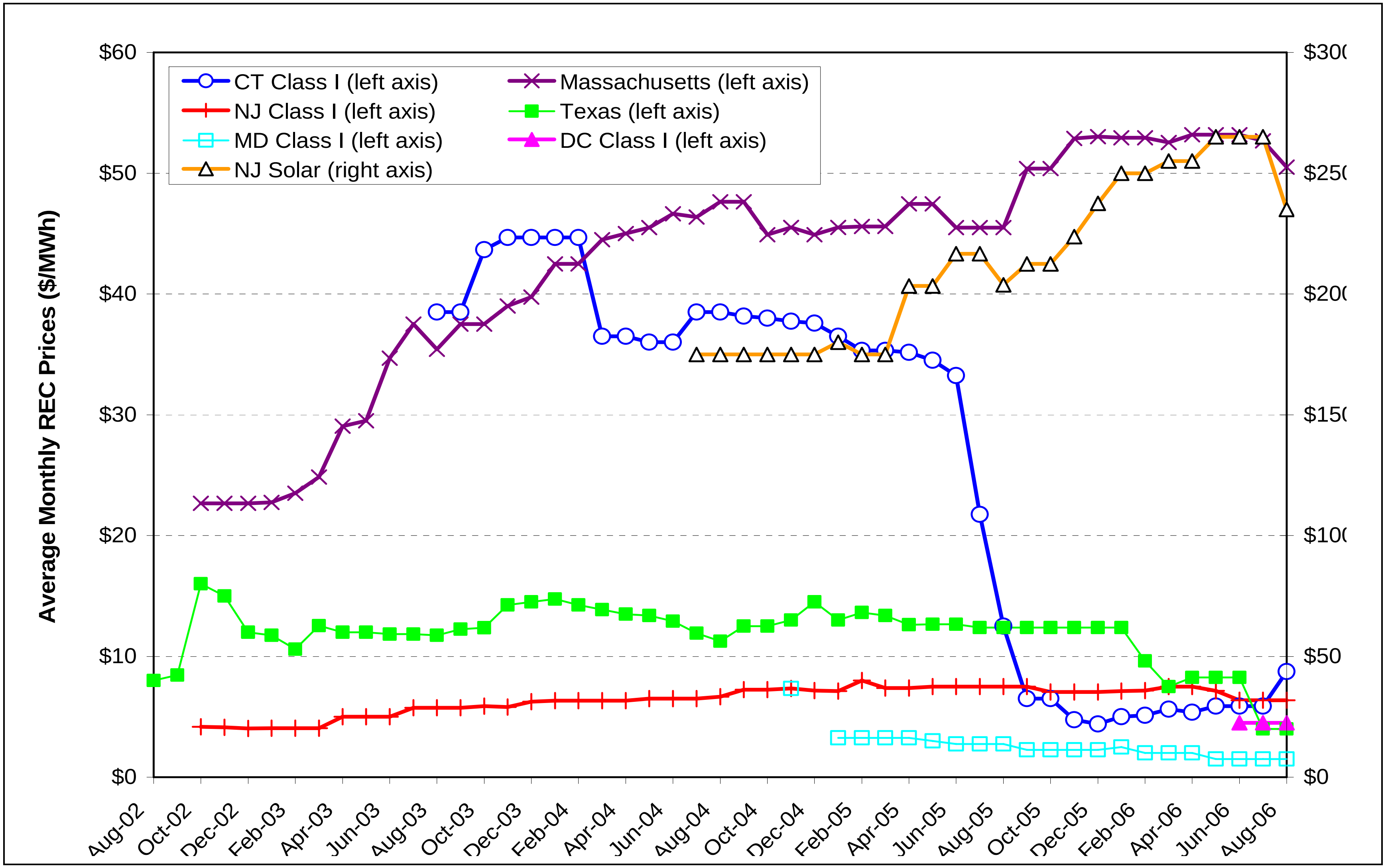
[120] Several limitations to these data deserve note: (1) though price data are available, they are limited to trades managed by Evolution Markets, and these markets are often not particularly liquid; and (2) averaging of price data often requires that one average trades representing renewable energy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

[121] 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.

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.

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.

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.[122]

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

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[122] 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 REC exceeds a pre-specified level (e.g., $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."

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 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.[123]

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

[123] 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.

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.)

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 RRTF, 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.[124]

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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[124] See New Renewable Resources Account Guidebook Volume 2B, page 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 almost complete lack of energy consideration on the part of land use decision making authorities and developers in their planning processes. Though many planners perceive themselves as applying smart growth principles, they most often omit 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 underestimated,[125] 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.[126] 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, using distributed generation (DG),[127] orienting residences in relation to the sun, increasing shading, incorporating roofs that reflect heat,[128] and installing energy efficient appliances are but a few non transportation-related strategies that would fall under a broader definition and produce significant energy savings.

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[125] 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

[126] 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.

[127] 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.

[128] Note that there are some parts of the state where roofs that retain heat may be preferable.

This chapter first describes California's current land use planning processes and the challenges and barriers affecting greater use of smart growth. Where possible, the chapter quantifies the energy benefits of smart growth, although benefits identified 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 real 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 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 potential 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.

Multiple barriers exist to changing the system as we know it. Moving away from the historical approach to planning to more energy-sustainable friendly planning has been difficult for the following reasons:

- Resistance to housing styles that are different from the American Dream of a single family home with a yard.
- Resistance to changing development formulas that appear to have widespread support and demand.
- Residents' opposition to higher density development in their communities.

- 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.
- 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.[129] The planning process involves the development of general plans and specific plans; imposition of zoning; subdivision of land; development

[129] California Constitution article XI, § 7

agreements; and the review of environmental impacts.[130] 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.[131]

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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[130] Government Code § 65100 et seq., § 65300 et seq., § 65800 et seq., § 65410 et seq., § 65864 et seq.

[131] 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[132] (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.

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. 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

[132] California Environmental Quality Act. Public Resources Code § 21000 et seq., Cal. Code Regs. Title 14; §§ 15000 – 15387 (CEQA Guidelines).

transportation projects. Often, COGs and MPOs cover identical areas and are a single entity.

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 State 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.

Energy providers, primarily investor-owned utilities (IOUs), have traditionally been 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, utilities 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.

Current Efforts to Integrate Land Use Planning with Energy Concerns

Consideration of energy concerns in the process of determining the use of land has enormous potential to help the state meet its energy goals. It requires an expanded role of local governments to imbed the state's energy goals in their decisions. Local agencies must also be encouraged to take up the GHG reduction challenge. A myriad of planning tools, new research, and new partnerships can also 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.[133] 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 pans 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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[133] 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.[134] 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.[135] 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 speak 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.[136] The element's goals—attaining a sustainable

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[134] 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.
[135] http://www.redwoodenergy.org/uploads/Energy%20Element%20Draft%208-05v2.pdf#search=%22humboldt%20county%20regional%20energy%20authority%22
[136] http://www.ci.pleasanton.ca.us/pdf/genplandraftenergyelement.pdf

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:

- 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,[137] 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.
- Provision of 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.[138] 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.

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137 http://icma.org/upload/library/IQ/117390.htm

138 http://www.sfgov.org/site/planning_index.asp?id=25527

- 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.

Chula Vista

The City of Chula Vista, near San Diego, 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."[139] 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 Area

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.[140] 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 will be an important tool in developing the 2007 regional transportation plan.

The San Diego region 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, sustainable, and efficient energy technologies and practices. SANDAG recently hired an energy specialist in recognition of the importance of energy considerations in planning.

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

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[139] Engle, D. 2006. With the Power at Hand: Examining the merits of distributed energy, Planning, July 2006, American Planning Association.

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

renewable energy and alternative vehicles and fuels.[141] 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.[142] 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 (SLO) 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.[143] The SLO County Department of Planning and Building is now offering expedited processing of projects that comply with smart growth principles. The City of SLO has adopted the Ahwahnee Principles,[144] and the Mayor has signed the U.S. Mayors Climate Protection Agreement.[145]

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 options, community choice ordinances related to purchasing renewable energy, and how building local will change the energy future. Local organizations such as SLO Green Build and ECOSLOW 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

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[141] http://www.sandiego.gov/environmental-services/sustainable/index.shtml
[142] City of San Diego Climate Protection Action Plan, July, 2005, http://www.sandiego.gov/environmental-services/sustainable/pdf/action_plan_07_05.pdf
[143] San Luis Obispo County Update, Morgan Rafferty, Environmental Center of San Luis Obispo, October 16, 2006.
[144] http://www.lgc.org/ahwahnee/principles.html
[145] Additional Update on San Luis Obispo Smart Energy Growth, Nick Alter, June 17, 2006.

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.

Further Action Is Needed to Integrate Land Use Planning and Energy

In spite of these exemplary actions, 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. First and foremost among these recommendations is expanding the definition of smart growth to include all energy elements. Only then can smart growth become an effective tool. 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 additional actions that will help to realize the benefits of integrating land use and energy.

Broaden the Definition of Smart Growth to Include All Energy Saving Strategies

Inclusion of sustainable land use and energy, distributed energy and renewables, as demonstrated by previous examples, is not typical of most current applications of smart growth. Based on a review of the literature and from comments received at the September 2006 Land Use and Energy workshop, the Energy Commission believes that the definition of smart growth must be broadened if the state is to achieve its energy goals. Smart growth developments should strive not only to reduce vehicle miles traveled, but also to incorporate distributed generation, increase the on-site use of renewable energy, orient residences in relation to the sun, increase shading, and include roofs, building materials and home appliances that minimize energy use. Broadening the definition in such a manner would provide additional strategies that would help the state meet its RPS goals, reduce its energy demands, and help negate the effects of global climate change.

Promote Smart Growth as an Integral Component of Reducing Greenhouse Gas Emissions

Assuming that all new U.S. housing were smart growth, with half greenfield and half brownfield,[146] the total nationwide savings after 10 years, based on a projected level of

[146] Land sites located within developed urban areas.

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.[147] 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 Assembly Bill 32 (Nuñez), Chapter 488, Statutes of 2006. 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.[148]

In the Climate Action Report, the land use and intelligent transportation systems strategies are projected to result in reductions of 5.5 million metric tons of CO_2 (MMTCE CO_2) by 2010 and 18 MMTCE by 2020. 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.
- Implementing intelligent transportation systems, traveler information/traffic control, and incident management.
- Accelerating the development of broadband infrastructure.
- Comprehensive, integrated, multimodal/intermodal transportation planning.

[147] Mary Jean Bürer and David B. Goldstein, Natural Resources Defense Counsel 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*.
[148] State Agency Work Plans, February 2006, http://www.climatechange.ca.gov/climate_action_team/reports/2006-02-06_AGENCY_WORKPLANS.PDF.

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	5.5	18
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

Experts expect these strategies to evolve over the next two years.

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.[149] 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.

Require Local Governments to Prepare GHG Reduction Plans

Local governments will be key to achieving the aggressive GHG emission reductions contained in the smart land use and energy efficiency measures identified in the Climate Action Team report. The Energy Commission supports local governments as the

[149] http://www.planning.org/policyguides/smartgrowth.htm

primary decision making entity for land use and discourages any state takeover of that function. Energy accounting should be a key element of city general plans, with local government leading the way and the state providing available resources, including funding that may be available through AB 32. Many local governments have already committed to reducing GHG emissions: over 40 California cities have signed the U.S. Mayors Climate Protection Agreement and committed their cities to meet or beat the U.S. emissions reduction target in the Kyoto Protocol. The Energy Commission intends to work with all stakeholders to develop legislation that would require local governments to develop GHG reduction plans in concert with state efforts to achieve the goals of AB 32.

Integrate Utilities in Land Use Decisions

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, such as Blueprint, 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.

The current focus of utilities remains on energy efficiency savings in construction and retrofitting. All three of the state's investor-owned utilities 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.[150] 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

[150] California Public Utilities Commission, http://www.cpuc.ca.gov/published/Final_decision/49859.htm.

and Electric (PG&E) has identified 17 local government partnerships and 3 statewide government partnerships for its 2006–2008 partnership portfolio.

Publicly owned utilities 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 publicly owned utilities 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 change that would require all new single family homes to be "zero-energy capable" by 2015. Challenges remain in undertaking such ventures. In 2005, a major effort by Austin Energy's Green Building Program, the City of Austin Neighborhood Housing and Community Development Department, and the Austin Housing Finance Corporation to implement a NetZero Energy Subdivision in one of Austin's disadvantaged neighborhoods was scrapped due to affordability issues.

Expand the Use of Tools Local Governments Need

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, as well as to reduce 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 utility by playing a prominent role in the Blueprint work recently completed in Sacramento. I-PLACE3S is currently being updated to include an energy module.[151]

The Energy Commission has the ability to fund energy and land use research through its Public Interest Energy Research (PIER) program as long as those funds advance science and/or technology not covered in private or regulated markets. Over the next several years, the Energy Commission will consider funding research projects that bolster local and regional governmental energy planning efforts. These research projects should

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[151] California Energy Commission, http://www.energy.ca.gov/places/index.html.

provide the scientific and technological background to inform sound decision and policy making in California. Several exciting research efforts exist.

- The Energy Commission, through the 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 energy analyses alongside established key planning data such as housing costs, vehicle miles traveled, infrastructure cost assessments, and air emissions.
- For local jurisdictions, the water system may represent over 50 percent of total energy use.[152] 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, water system related decisions.
- Within the next 25 years, the U.S. will design and construct more than 213 billion square feet of new built 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 together 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 uses the Clean Air Climate Protection (CACP) software to store, organize, and analyze data for larger efforts 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, Harmonized Emissions Analysis Tool that 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.

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[152] 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

- 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.[153]
- 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 Leep Workbook describes a basic five-step process that communities can follow to increase their level of energy efficiency activity.[154]
- 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 Counsel 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 Energy Commission may be able to leverage the LEED–ND program in a way that assists in establishing standards or priorities for growth in California. It is considering conducting research and analysis into the adequacy, robustness, and opportunities for improvement of the draft LEED–ND standards. Once the LEED–ND standards are final, follow-up projects could include monitoring and validating the impact of the standards and analyzing and quantifying the benefits. If the standards work satisfactorily, the Energy Commission may consider recommending that development projects receiving LEED–ND certification receive expedited consideration and approval from city officials. Or if appropriate, the Commission may develop California standards or development priorities modeled from LEED–ND.
- 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

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153 http://www.ctg-net.com/energetics/News/CTG_Sustainable_Communities_Model.htm
154 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.[155]

Conduct 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*.[156] This roadmap identified areas of needed research, focusing on the connection between municipal governments and electricity use. As noted in this roadmap and by many attendees and commentators of 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 planning practices and designs. Further, information is needed to better understand the associated complex 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. Efforts to reduce congestion and improve air quality have led to metropolitan transportation plans and regional Blueprints that result in future reductions in vehicle miles traveled and hence transportation fuel use. However, additional links exist 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, reducing transportation costs will benefit those with lower incomes since

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

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 or reduced use of energy 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 Roadmap are necessary. These updates will more precisely identify and describe existing and emerging research needs and, in turn, to initiate appropriate research.

Educate Stakeholders on Energy Links to Smart Growth

Local communities are moving in the smart growth direction but need help in understanding the energy options available to them, the tools they can use to facilitate smart growth that incorporate energy concerns, and the benefits that would accrue to both local government and the public. Providing information and education will be critical. An effective outreach program would include answers to these questions, as well as introductions to and instructions on using planning tools such as I-PLACE3S.

Much information exists on discrete topics but no central repository exists to provide the full range of information that local governments will need to reduce energy and GHG emissions. Resources include the Local Government Council, the American Planning Association (APA), ICLEI, and others who are actively augmenting current efforts to incorporate energy considerations in local land use planning. Information from these and other groups should be compiled through such mechanisms as a dedicated Web page or a university or research center.

The 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. Such efforts need expansion.

Identify and Promote 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 will be 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).[157] 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 reflect the dollars saved by reduced transportation fuel costs from locating near transit and in mixed-use developments and by reduced electricity and gas bills through energy-efficiency.

The Location Efficient Mortgage® is a mortgage that helps people become homeowners in location efficient communities.[158] 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 Counsel, and the Surface Transportation Policy Project. However, currently only two California lenders, located in San Francisco and Los Angeles, provide location-efficient mortgages. In addition, one lender with offices in several western states provides energy efficient mortgages.

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 percent on the debt-to-income requirements for EEMs. Freddie Mac allows lenders to use the projected utility savings as a "compensating factor."[159]

Expanding the number of lenders who understand the benefits of energy efficient and location-efficient homes would be an important step in expanding the use of energy efficient and location-efficient mortgages. However, certain 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, that help to make them more attractive in the marketplace. Finally, guidelines do exist for including the cost of energy efficient

[157] 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.
[158] http://www.locationefficiency.com/.
[159] http://www.pueblo.gsa.gov/cic_text/housing/energy_mort/energy-mortgage.htm

improvements in home appraisals, but most appraisers are not aware of and have no experience in using them.[160]

As previously mentioned, utilities are working with communities to provide incentives to advance energy efficiency. Through its Tax Exempt Customer Incentive Program, 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 provided $19 million in funding in 2005 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 upzoned.[161] 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

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[160] Challenges in Offering Energy Efficient Mortgages, Kevin Hauber, The Mortgage House, October 16, 2006.
[161] Making Smart Growth Work, Pacific Energy Policy Center, June 2006.

Smart Growth.[162] The state's "Live Near Your Work" program provides financial incentives for employees to purchase homes near their workplaces.[163]

Develop Land Use / Energy Partnerships

Helping local governments develop and implement 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 anticipates inviting stakeholders to participate in an ongoing land use/energy working group that would convene on a regular basis to discuss land use and energy issues in general and local GHG reduction plans in particular. Additional workshops may be held as part of the 2007 Integrated Energy Policy Report process to track the development of the information and actions defined above.

Conclusion

An initial examination of existing studies and policies related to sustainable land use, or smart growth, and energy saving opportunities suggests that smart growth offers enormous potential to help meet the state's energy goals. Yet it also showed that few smart growth efforts consider energy resources and infrastructure in the planning process. In addition to its overarching recommendation to integrate energy considerations into all land use planning efforts, the Energy Commission offers a number of additional recommended actions to solidify the smart growth/energy savings connection:

- Local governments should continue as the primary planning authority for land use and should be responsible for preparing local GHG reduction plans under AB 32..
- The state should work with local governments to develop and implement greenhouse reduction plans.
- Planning entities should capitalize on existing state and local government efforts to advance smart growth and energy initiatives, such as Assembly Bill 857 (Wiggins) Chapter 1016, Statutes of 2002.
- Planning efforts should include utilities to take advantage of their expertise and experience with the entire range of energy issues, including infrastructure and other support systems.

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

[163] 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

- The state and federal governments and private enterprise should expand and continue to develop smart growth tools for use by local governments.
- The Energy Commission should conduct research on fundamental aspects of land use and energy.
- The Energy Commission, local government planning entities and all stakeholders should educate each other, other stakeholders and the public on the need to incorporate energy considerations in any land use planning activities.
- The Energy Commission should promote and help local governments identify funding options to expand smart growth.
- All stakeholders should look for opportunities to develop smart growth-energy partnerships.

By more fully understanding the land use/energy relationship and developing measures to accommodate that relationship, California can make significant and swift progress in meeting its energy goals.

APPENDIX A: ACRONYMS USED IN THE 2006 INTEGRATED ENERGY POLICY REPORT UPDATE

APA	—	American Planning Association
BLM	—	Bureau of Land Management
CAISO	—	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
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
MOA	—	Memorandum of Agreement
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
PEA	—	Proponent's Environmental Assessment
PEIS	—	Programmatic Environmental Impact Statement
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
PTC	—	Production Tax Credit
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 Associate 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