Renewable Energy for California

Benefits, Status & Potential

REPP

Renewable Energy Policy Project

Research Report No. 15 | March 2002

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Published March 2002, Washington, D.C.

PRINTED IN THE UNITED STATES OF AMERICA

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Renewable Energy for California: Benefits, Status and Potential

By Fredric Beck, Renewable Energy Policy Project; Jan Hamrin and Kirk Brown, Center for Resource Solutions; Richard Sedano, Regulatory Assistance Project; and Virinder Singh

Introduction

California has been the historic leader in the United States in renewable energy. In the brief history of retail choice in the state, a significant portion of Californians have also demonstrated that they are interested in buying electricity that has a significant and demonstrable fraction of renewable resources. But in 2000 and early 2001, California experienced an energy crisis that has raised fundamental issues about its sources of electricity and their relationship to both price stability and environmental quality. In this context, renewable energy has emerged as one subject among many in the debate about new sources of energy.

This report discusses the importance of renewable energy to Californians concerned about price, reliability and environmental quality. The report also explores the future potential for renewable energy in California and identifies important policy options to ensure that renewables' multiple benefits are realized through the development of a diversified portfolio of energy sources both now and in the future.

This paper is divided into four sections:

- Part I provides background on two key sources of conventional power for California—natural gas and coal—and some of the risks they pose to Californians.
- Part II discusses how renewable energy can help reduce financial and environmental risks of power generation while improving power reliability.
- Part III estimates the potential for new renewable energy (wind, geothermal, solar photovoltaics (PV) and biomass) as well as pumped hydro storage in California.
- Part IV outlines policy options, such as systems benefit charges, renewable portfolio standards and others that California could adopt to help capture the benefits of renewable energy.

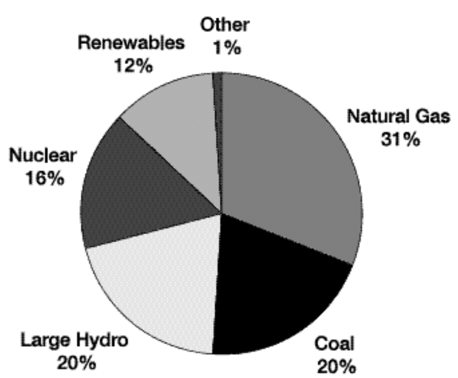
The authors thank Tina Kaarsberg, Larry Goldstein, Bill Babiuch, Paul Galen, Zia Haq, Scott Sklar, Randy Swisher, Roby Roberts, Alan Miller, Renz Jennings, Ryan Wiser, Nancy Rader, Mark Bolinger, George Sterzinger, Karl Rábago, Lynne Gillette, Barbara Farhar and Margaret Mann for their review comments on this report. Research for this paper was funded by a grant from the U.S. Department of Energy's National Renewable Energy Laboratory. The content of this paper is the sole responsibility of the authors, and does not necessarily reflect the opinions of the funding organization, REPP, the REPP Board of Directors, the Center for Resource Solutions, the Regulatory Assistance Project, or the reviewers.

Part I.
California's Power: Sources, Trends, & Challenges

1.1 California's Power Mix

In 1999, California's power generation mix consisted of 31% natural gas, 20% each for large hydro and coal, 16% nuclear and 12% renewables (see Figure 1.1).[1] Approximately 84% of California's power is generated in-state, with the remaining 16% imported from out-of-state (9% from the Northwest and 7% from the Southwest). Geothermal energy made the largest contribution to California's renewable power generation, followed by small hydropower and biomass and organic waste as the next largest sources of power

Figure 1.1 California's Electricity Generation Mix by Source, 1999



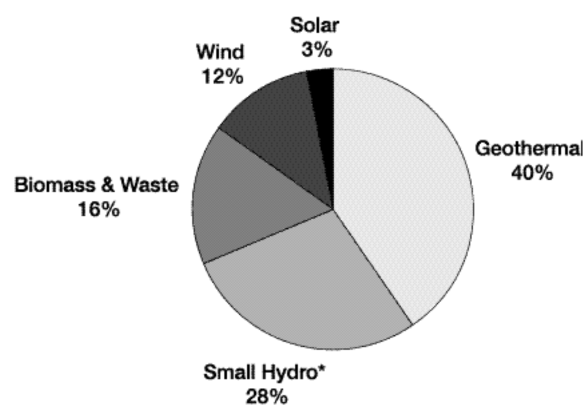
Source: California Energy Commission. Net System Power Calculation, 1999. (Sacramento: April 5, 2000.) Accessed December 13, 2001 at http://38.144.192.166/reports/2000-04-14_300-00-004.PDF

1.2 Power Demand and Increasing Reliance on Power Imports

California, along with most of the rest of the Western U.S., built up a surplus of generating capacity in the 1980s. This resulted from the addition of several large generating plants and the development of 9,000 megawatts (MW) of non-utility capacity in the state, as well as slow economic growth in the early 1990s that depressed electricity demand. However, while California's average annual load growth was less than 1% from 1993 to 1995, it increased by almost 4% per year on average from 1996 to 1998.

Within the Western Systems Coordinating Council (WSCC), the regional electric reliability council that includes California, summer peak load in the Arizona region[2] grew by 7.9% annually from 1982 to 1998, much faster than California's annual load growth rate of 3.2% over the same period.[3] Growth in the Arizona region and other western states eventually consumed surplus generating capacity faster than expected, limiting opportunities for California to import power.

Figure 1.2 California's Renewable Electricity Generation Mix by Source, 1999



* Here small hydro is defined as installations of less than 30 MW of hydropower capacity.
Source: California Energy Commission. Net System Power Calculation, 1999. (Sacramento: April 5, 2000.) Accessed December 13, 2001 at <http://38.144.192.166/reports/2000-04-14_300-00-004.PDF>

Yet California did not add more power plants to meet higher demand in the mid- to late-1990s: Two contributing factors to the decision were forecasts predicting excess capacity and uncertainty about the impacts of restructuring on electricity markets.

- In 1995, for instance, the California Energy Commission (CEC) released its electricity forecast, predicting both Pacific Gas and Electric (PG&E) and Southern California Edison (SCE) would have reserve margins of over 20% in 2001, resulting in power surpluses of over 2,000 MW for both companies combined.[4] At least one utility, SCE, believed it would not need new generating capacity until 2004.

- The length and complexity of California's electric restructuring process also were contributing factors to the 2000-2001 energy crisis. Almost four years passed from the California Public Utilities Commission's first proposal to retail competition in 1994 to retail competition being officially launched in 1998. Uncertainty about how the new markets would be designed, utilities' fear of adding stranded costs if new power plants were constructed and demand did not materialize, and the desire of those entities with a significant market share to preserve it all pointed towards avoiding large new capital investments like generating plants.

Less than 700 MW of new capacity was added to California's generating mix between 1995 and 1999, while peak load increased by over 5,500 MW. California was not unique.[5] Demand for electricity grew by a total of 24% in the last decade in the Pacific Northwest, while generating capacity grew by only 4%. The WSCC region (including California and the Pacific Northwest) added an average of 1,200 MW of new capacity annually from 1991 to 1998, an average annual growth rate of less than 1%.[6]

As a consequence, California became increasingly dependent on imported power from the Pacific Northwest and the Southwest. California's reliance on imported power increased by almost 40% between 1995 and 1998, largely from increased imports of natural gas. [7]

1.3 Increasing Dependence on Natural Gas

Over the last two decades, electric utilities have looked to natural gas power plants to provide cheap power relative to nuclear, coal and renewables.

Most of California's gas supply is imported—up to 80%. Pipeline capacity in California is often inadequate to meet winter demand. Historically, PG&E and Southern California Gas stored large amounts of natural gas in storage fields to ensure adequate gas was available for the winter season. Due to the effects of deregulation on natural gas markets, the amount of gas in storage by the end of 2000 fell almost 90% below what was stored in 1998 and 1999.[8] An August 2000 explosion on the El Paso Natural Gas pipeline, a primary pipeline into California, further reduced gas supplies into the state. Another pipeline was also having problems with a compressor station and abnormally low temperatures served to increase the demand for natural gas. Some researchers estimated that natural gas demand in California rose to as much as 9 billion cubic feet (Bcf), well over the state's normal import capacity of 7.3 Bcf.[9] This combination of high demand and low supply caused a sharp increase in gas prices from \$2 to \$3 per million BTU (MMBTU) in the Summer of 2000 to \$60 per MMBTU in October 2000, a 20- to 30-fold price increase.

Demand for natural gas remains very high and is still increasing in California and across the nation. As of October 2001, California announced over 10,000 MW of new natural gas power plants to be built. As is discussed in more detail in Part Two of this report, the increasing demand for and dependence on natural gas for power generation, as well as the potential for high natural gas price spikes, exposes California's power suppliers and consumers to significant financial risks. The addition of renewable energy technologies can add diversity to California's resource mix, thereby decreasing dependence on natural gas and reducing these risks.

1.4 Environmental Challenges of Fossil Fuels Use

Electricity generation from fossil fuel sources releases emissions that contribute to global climate change as well as to health and environmental damage from acid rain and urban smog. In 2000, the electricity sector accounted for 40% of the nation's carbon dioxide emissions,[10] with 80% of these electric sector carbon dioxide emissions coming from coal-fired generation.[11] In addition, in 1997, electric power plants accounted for 64% of the nation's sulfur dioxide emissions and 26% of the nation's nitrogen oxide emissions.[12]

Approximately 50% of California's generating mix is from fossil fuels—about 30% from natural gas and 20% from coal. While natural gas plants are the new power plants of choice, interest in coal power is resurging due to high natural gas prices. However, because laws governing coal plant emissions are likely to become more stringent, increasing emission compliance costs may cause future coal-fired power prices to increase. Thus, coal power poses a potential price risk to Californians due to its air emissions.

California's generating plants are also aging—55% of the state's generating plants are over 30 years old, and about three-fourths of the natural gas and oil-fired electric capacity in California was installed before 1980.[13] Older generating units need to be taken off-line more often for service than newer generating facilities, and they are also not as fuel-efficient or as clean as newer generating plants. Because California's in-state generating resources are not likely to match California's electric demand requirements until at least 2003, these older generating facilities will have to continue to operate at high levels of output over the next several years, increasing the potential for maintenance problems that can lead to generation shortfalls, higher energy prices and decreased reliability.

Part II. Renewable Energy's Role in Risk Mitigation

Renewable energy can supply clean reliable power to help California mitigate many types of risks it faces in the electrical power sector. Two benefits of renewables follow from the preceding discussion:

- Renewable energy can reduce financial risk to consumers and suppliers, alleviating uncertainties about future fuel costs and future demand and reducing the potential for overcapacity and stranded assets.

- Renewable energy can reduce environmental risk by reducing uncertainty about future environmental regulations and potential emission offset price increases.

In addition, renewables can help reduce risks of supply interruptions due to reduced availability of power or fuel imports, off-line generating plants and rainfall variability that effects hydro-electric generation.

2.1 Reducing Financial Risks

The United States has invested billions of dollars into power plants, power lines, meters and other essential components of the electricity system. Since so much money goes into electricity, and since it is an essential commodity that Americans cannot do without, it is sensible to think about these investments in terms of risk. In particular, Californians—as consumers and investors—must decide what mix of electric power technologies offers the best performance and the lowest financial risk.

Lower Risks Due to Less Reliance on Fossil Fuels

Overall, the price risks of non-hydropower renewables (wind, geothermal, biomass and solar) are largely unrelated to changes in (a) natural gas supply, (b) hydropower supply and even (c) environmental regulations. This is especially true if they are deployed with long-term contracts that are appropriate for fuel-free renewables. In addition, biomass power plants can benefit from predictable fuel price streams, ensuring their ability to pay relatively stable prices for biomass into the future. Unless the renewables price is artificially tied to the price of conventional energy, renewables' sources of price (and performance) risk are unrelated to price risk for natural gas or hydropower.

In financial portfolio theory, lowering portfolio risk requires collecting investments that exhibit random risk when compared to each other. Products or companies that have a portfolio with correlated risk patterns, offer little risk reduction since everything in an investors' portfolio will go in the same direction due to a certain trend. [14] Because renewables' price and performance risks are in general uncorrelated with those of fossil fuels or hydropower, renewables constitute an important source of investment diversification in a state or utilities energy portfolio.

Geothermal and biomass plants, unlike wind and solar, require resource inputs such as water and biomass fuels. Geothermal plants may require water to pump into the ground to generate steam. But because this water can be waste water (as is currently used in the Geysers geothermal production area), the resource price risk for geothermal energy is only loosely tied to the price of water.

Since biomass plants rely on fuel delivered by fossil-powered transportation systems, biomass plants in California face the greatest correlated price risk compared to other sources of power. Biomass power plants rely on residues from farming, forestry and mill operations, as well as urban wood waste such as pallets. Thus, their performance is related to available biomass supply and price, which can vary slightly with changes in agricultural patterns or forestry management plans, as well as demand from competing consumers such as the mulch industry. If biopower plants are called upon to operate more often due to low supply or expensive prices from other kinds of power plants, there can be increased demand for available biomass resources that can raise biomass fuel prices.

Finally, there is a greater short-term risk of increased prices due to increased demand for the newest types of renewable energy installations, such as PV and wind. The newer renewable energy technology firms may not have enough inventory and manufacturing capacity to meet such short-term demand. However, prices for all renewables are expected to decline steadily over time, so that the farther into the future they are relied upon for new electricity generation, the cheaper they will be.[15] This monotonic decline differs from the outlook for natural gas prices, which the U.S. Energy Information Administration predicts may either rise or fall by 2020, depending on developments in natural gas exploration and extraction techniques.[16] Since fuel prices can represent 65% of power generation costs, such volatility will translate into volatile power prices from natural gas plants.

Better Project Cost Management

The newer renewable technologies are "modular" technologies that are flexible in size—a wind farm can include two wind turbines or thousands of turbines. Instead of investing in high-capital, long-lead time projects, such modular technology allows investment in smaller capacity increments. While some natural gas technologies also feature such modularity, none can compete with the smallest renewables (e.g., PV) for modularity and fuel supply requirements may decrease the value of their modularity.

Small increments of additional generating capacity help to:

<u>Address uncertain demand growth</u>. With smaller capital expenditures per increment and much shorter lead times, modular systems can help avoid excess capital costs if demand predictions are wrong.[17] In uncertain demand environments, modular systems allow investors to mitigate financial risk by embarking on staged investment programs that closely match demand growth in quality and location.

<u>Provide better project cost management</u>. Because modular systems have shorter construction lead times, investors are able to react quickly to changing market conditions. Projects with short lead times tend to have greater certainty associated with their installed cost due to fewer cost overruns and less lost revenue due to plant construction delays. [18]

<u>Take advantage of technological learning and economies of production</u>. Modular plants based on manufactured technologies reduce financial risk by allowing investors the opportunity to take advantage of lower costs due to technical advances and manufacturing learning curves while construction is in progress. Where a large capacity upgrade can be deferred by a smaller investment in modular technology, more information about future prices can be gained. The option to delay investing has informational value. By investing in modular upgrades, this value can be realized. [19]

<u>Offer a greater degree of investment reversibility</u>. Compared to large, custom projects, modular plants are likely to have a higher salvage value

than non-modular plants, providing some reversibility of investment. An example is the 6 MW Carrisa Plains PV plant facility in California, whose original owner, Arco Solar, sold the plant for strategic reasons to another company. The new owner dismantled the plant and the modules were resold at a retail price of $4,000 to $5,000 per kilowatt (kW) at a time when new modules were selling for $6,500 to $7,000 per kW.[20]

Rapid Response to Changes in Demand

The more modular renewable energy systems such as new wind and PV [21] may provide a quicker response to demand for new power plant construction than central-station plants.[22] Because wind and solar have fewer environmental impacts than fossil or nuclear power plants, they may be sited and permitted more quickly. Once sited, solar and wind power can be installed on a scale of a few months to a year. [23]

Additionally, as each PV panel or wind turbine is put into place, it may begin producing power immediately, rather than having to wait for an entire power plant to come on-line before being operational. Quicker siting and installation means that energy and revenues will be provided sooner than by non-modular generating options.

Modular power systems also allow for rapid incremental capacity additions to existing sites. Because the new generating units are prefabricated and ready for installation once they arrive at the site, capacity additions can be accomplished rapidly. In contrast, such additions at a central-station fossil fuel plant requires taking a major portion of the plant's capacity off-line, and the construction time for retrofitting is likely to be greater, limiting the plants grid capacity contribution and resulting in greater lost revenues than with a more modular system.

2.2 Reducing Exposure to Environmental Regulatory Risk

Companies that own fossil fuel power plants have cited the need to install scrubbers at the end of smokestacks, the need to switch fuels (e.g., high-sulfur coal to low-sulfur coal) and the requirement to pay monetary penalties in case they exceed emissions limits as examples of burdensome environmental regulatory costs.

It is very difficult to predict the precise cost of complying with environmental regulations, since an array of pollution control strategies are available. In addition, future strategies are hard to anticipate and depend upon technological change and seemingly unrelated trends affecting ambient air quality such as transportation policy and macroeconomic trends that influence the entire U.S. economy.[24]

Apart from compliance costs, a broader source of uncertainty is the likelihood of more stringent environmental regulations. Predicting regulations is fraught with the challenge of predicting political behavior by the executive, legislative and judicial branches as much as predicting new information on health and environmental impacts of pollution. Planning for new regulations is especially difficult given that different regulatory authorities regulate different media (air, water and waste, among others) and even different pollutants on different schedules. Thus, the range of possible regulation combinations and associated costs can vary widely.

The cost of environmental compliance may or may not be passed on to consumers, depending upon prevailing contract and spot market dynamics. Under the recent bidding structures in the California spot market, it is likely that the high costs of purchasing NOx credits in the RECLAIM program in Southern California were reflected in the bid prices for plants in the spot market. In the future, it is also unlikely that power companies will swallow all of the costs, though the ability for compliance costs to translate into market-clearing prices should greatly diminish. Power plant owners facing high regulatory costs will insist on passing the costs to consumers. Thus, regulatory risk for generators translates into price risk for all Californians.[25]

Upcoming Regulations

Electric power producers cope with uncertainties by assigning probabilities to different regulatory outcomes, and then assigning a cost to each probability based on estimated compliance costs. In general, a number of regulations affecting power plants are in place or looming:

- Federal standards for mercury are likely by 2005, possibly in the form of a "three-pollutant" standard that also encompasses nitrogen oxides and sulfur dioxide.

- The stringent Phase II of the sulfur dioxide control program began in 2000 and will affect the electricity sector for many years to come.

- Regulations for fine particulates may come into effect by 2005.

- In the West, the Western Regional Air Partnership will place regulations on power plants that affect visibility in national parks such as Grand Canyon.

- Greenhouse gas reduction policies are backed by growing multinational calls for limits on carbon dioxide. Carbon dioxide cuts are particularly important for regulatory risk. All forms of fossil fuels, from coal to natural gas, will face potential requirements to cut emissions through greater efficiencies. Power plant owners may be forced to turn to low- and zero-emissions power sources such as renewables to comply with such limits.

Implications for California

Environmental regulations have implications for California both in terms of the power supply mix itself and the regional air quality districts in which generating plants are located.

Challenges Faced by Different Sources of Power

For different types of power plants, certain regulations herald higher costs than others. For example:

<u>Coal</u>. Coal power plants, which produce 20% of the power consumed by Californians, are first in line when the power sector must cut emissions of "criteria" air pollutants such as nitrogen oxide, sulfur dioxide and air toxics such as mercury, plus carbon dioxide. In fact, coal plants currently have no effective retrofit options to cut CO_2 emissions.[26] Power plants that feed California, such as the Mojave plant in Nevada and the Navajo plant in Arizona, were built before 1975 and are part of the dirtiest plant fleet in the nation because fewer emission controls are required for "grandfathered" power plants. The Mojave plant faces tight SO_2, NOx and particulate matter restrictions imposed by the U.S. EPA to improve visibility in the Grand Canyon.[27]

For coal plants, regulations for criteria air pollutants and climate change all portend significant compliance costs. For example, the Centralia coal plant in Washington state paid $436 million in scrubber costs to meet stringent sulfur dioxide regulations—thereby raising the cost of electricity by 60% to 160%.[28] (The state government and state taxpayers paid for the scrubbers, otherwise the plant faced closure.)

Natural gas. New combined-cycle natural gas power plants emit relatively few "criteria" air pollutants compared to coal power plants. All of the new plants under construction in California as of late 2001 are natural gas plants. However, these plants may have to pay for stringent climate change policies limiting carbon dioxide emissions. One estimate finds that new carbon dioxide limits could raise variable costs at new natural gas plants by 25%.[29]

Diesel. In the distributed generation (DG) market, diesel generators in California will likely face strict emissions standards. Although the newest generators are much cleaner, the installed base of emergency and standby diesel generators around the nation release similar quantities of nitrogen oxide and carbon dioxide as all power plants in New York, Pennsylvania and New Jersey com-bined.[30] They also tend to operate more in the summer—producing proportionately more pollution in the hotter temperatures—as sources of back-up power and power for construction projects.

Legislation passed in October 2000 directs the California Air Resources Board (CARB) to compare small power sources with central-station, combined-cycle natural gas power plants when setting emissions limits. Based upon analysis funded by CARB, only wind and solar, plus fuel cells with significant waste heat recovery, are competitive with combined-cycle natural gas plants for reducing air pollution from power generation.[31] As such, these renewables can provide new power without degrading air quality requirements in areas that can ill afford more air pollution.[32]

Challenges Faced by Regional Air Quality Districts

Specific regions in California have more to lose than others by hosting polluting power plants. The San Joaquin and Sacramento Valley, most of Southern California and the Bay Area all are in violation of Clean Air Act standards for ozone (to which nitrogen oxide is an important contributor) and particulate matter.[33] These regions face federal penalties for noncompliance, including barriers to siting new businesses within the region due to more stringent requirements for emissions controls, as well as withheld transportation funds. The CEC notes that "[t]he majority of California's power plants are located in the state's most severely polluted areas, South Coast and San Joaquin Valley; or most densely populated areas, San Francisco Bay Area and San Diego County."[34] While automobiles and dispersed pollution sources should face steeper cuts than power plants in future in-state compliance strategies, the fact that power plants are easier to regulate than smaller sources will mean that power plants will face local regulatory pressure if noncompliance persists.

2.3 Improving Reliability

Ability to Meet Peak Demand

Biomass and geothermal can supply baseload capacity to the grid to meet both seasonal and daily electricity demand peaks. One variable renewable, solar, produces the most power during peak loads, thereby reducing the risk of service interruptions from constrained utility generating and transmission capacity during periods of high peak demand.

There is tremendous value in supplying peak power. One analysis of load reduction in California during summertime peak periods through both energy efficiency and renewable energy found that the value of reducing load was up to 150% and 600% of the market price for power.[35] Renewables that can operate during peak demand not only save a utility money by avoiding peak fuel charges, they can also help mitigate price increases for fuels purchased by a utility for fossil-fired generation.

After reviewing the major reliability events from 1996 to 2000, the Regulatory Assistance Project (RAP) found the underlying cause of these reliability problems was, in almost every case, the high demand the system was required to serve at the time of failure.[36] California's electricity demand is extremely temperature sensitive, driven in large part by commercial air conditioning demand. Because of this, California's electric power demand peaks in the summer months, typically July and August, and is lowest in the winter and early spring. In 1999, summer peak demand was almost 50% greater than winter peak demand (see Figure 2.1).[37]

California's power demand also peaks on a daily basis, with summer demand typically peaking in the mid- to late-afternoon (see Figure 2.2).[38] Summer afternoon peak loads can be more than double daily minimum loads.[39]

Wind power generally peaks in the summer months in California, making it an important

Figure 2.1 California-Mexico Power Area Actual Peak and Energy Loads for 1999

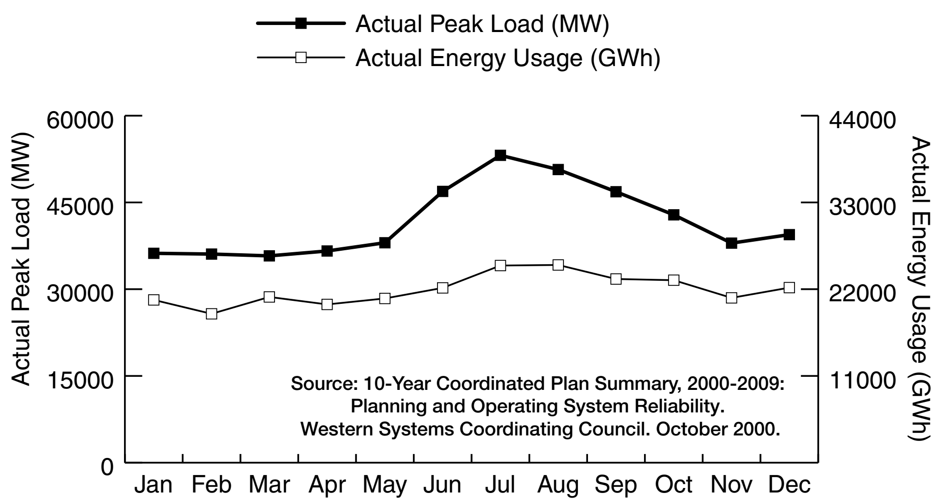
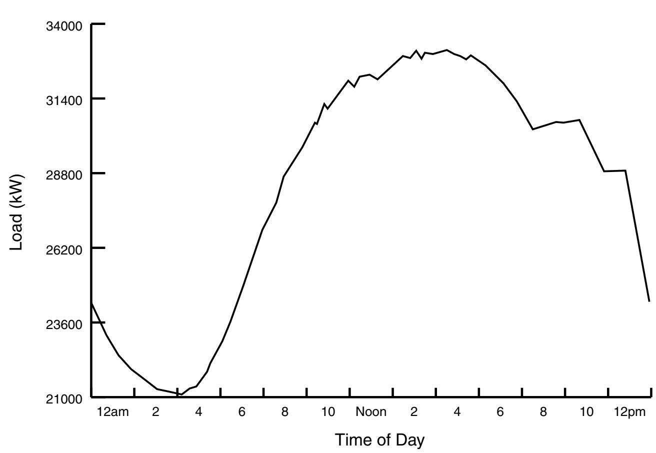


Figure 2.2 Typical California Daily Load Profile, May 2001



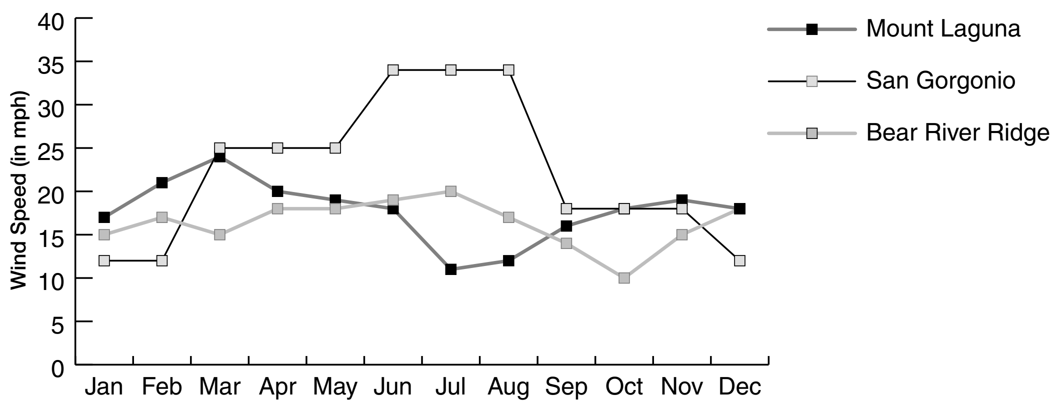
Source: California ISO website <http://www.caiso.com/SystemStatus.html>

option for supplying peaking capacity for grid support on a seasonal basis. Some California wind patterns appear to have sharp peaks in availability beginning in May and lasting until late August and early September (see Figure 2.3). A study by the CEC in 1997 found that 74% of total power production from four wind farms in California took place from April through September.[40] Of course, daily wind availability is variable for an individual wind plant (see Figure 2.4).[41]

Daytime peaks in renewable generation are more predictable in the case of PV. One study found that PV could deliver firm, dependable power during extreme peak conditions leading to outage situations.[42] The analysis focuses on PV's effective load carrying capacity (ELCC), which is the probability that PV can contribute to a utilities capacity to meet its load. PV's ELCC is not well correlated to the intensity of the solar resource, but is highly correlated with the extent to which PV output and a utilities load curve are well matched. In other words, a region with comparatively low solar resources may still have a high PV capacity credit if the utility load and solar resource are well matched.

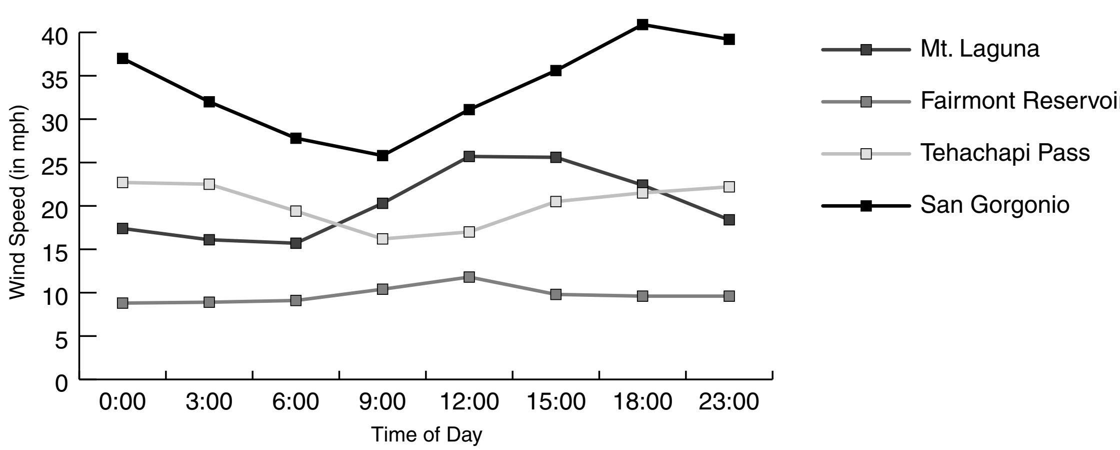
The degree of this match is related to the summer-to-winter peak (SWP) load ratio. Figure

Figure 2.3 Monthly California Wind Speeds, Selected Sites



Source: Based on data from Osman Sezgen, Chris Marnay and Sarah Bretz. Lawrence Berkeley National Laboratory. Wind Generation in the Future Competitive California Power Market. (Berkeley, CA: March 1998)

Figure 2.4 Summer Daily Wind Speeds, Key Southern California Wind Sites



Source: Based on data from Osman Sezgen, Chris Marnay and Sarah Bretz. Lawrence Berkeley National Laboratory. Wind Generation in the Future Competitive California Power Market. (Berkeley, CA: March 1998)

2.5 shows the relationship between PV's ELCC and SWP ratio for a hypothetical 2% grid penetration of PV. [43] California's SWP ratio was 1.5 in 1999. At this SWP ratio PV's effective capacity would be about 80% of its nameplate rating, meaning that one MW of PV capacity in California at 2% grid penetration is equivalent to 800 kW of dispatchable power at peak load.

Power Near the Customer

Since modular technologies such as wind and solar can be small in capacity, they can serve as DG that can improve the reliability of local distribution grids. DG provides power close to the users, whether on their roof or nearby at some point in the local distribution grid. By adding small increments of generating capacity at key points on local or regional distribution grids, DG protects customers from constraints on the long-distance transmission system, which ships power from distant power plants to the local distribution grid. Thus, DG capacity improves power reliability for local consumers.

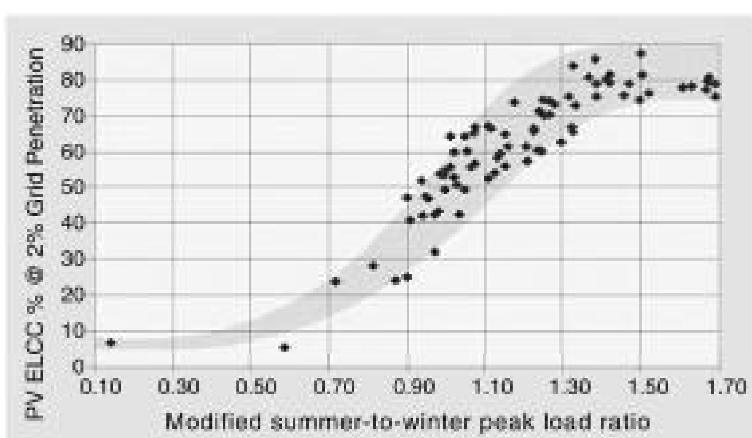
DG includes a wide array of technologies, such as natural gas fired micro turbines, fuel cells, diesel-powered generators and combustion turbines, as well as renewable technologies such as solar PV and wind turbines. DG provides different benefits for both utilities and customers.

DG can save utilities money by:
- Reducing line-losses through providing generation closer to the end user
- Deferring transmission and distribution (T&D) line upgrade expenditures
- Delaying or eliminating the need to build new T&D lines and/or new central-station generating plants
- Reducing transmission and capacity charges
- Reducing fuel costs

DG located on the customer's site can save customers money by:
- Avoiding expensive blackouts that disrupt business operations
- Providing an alternative to grid power during expensive peak times
- Offering an alternative to utility power, thereby signaling to power suppliers that high prices can be met by customer switches to private generation

The primary economic value of distributed resources for utilities, and therefore for their ratepayers, comes from reducing or deferring investments in T&D and from improved system reliability.[44] Because there is no spot market or reserve market to call forth additional wires in hours of peak need, distributed resources have particular value in supplying capacity to support the reliability of local wires.[45]

Figure 2.5 PV's Effective Load Carrying Capacity (ELCC)



Shorter lead times for construction, more flexible siting and less financial risk are the benefits of modularity that give DG an economic advantage over conventional wires.

Less Down Time

Modular energy systems are inherently more reliable than large, non-modular systems because they have less variance in equipment availability. Non-modular plants, such as central-station plants, are either on-line or off-line. In May 2001, almost one-third of California's central station generating capacity was off-line for maintenance when unseasonably hot weather raised peak demand beyond the state's capacity to provide electricity.[46] The result was rolling blackouts over a three-day period.

In contrast, the use of modular plants allows maintenance on a partial basis. For example, at any one point in time only 5% of a modular plant's capacity might be down for maintenance, while the other 95% continues to generate. Variance decreases as the number of modules increases, thus availability is more predictable as more modular capacity is added to the generation mix.[47] Modular plants also reduce the risk of blackouts because the amount of reserve capacity required to meet a given level of reliability is reduced when using power systems based on small modules.[48]

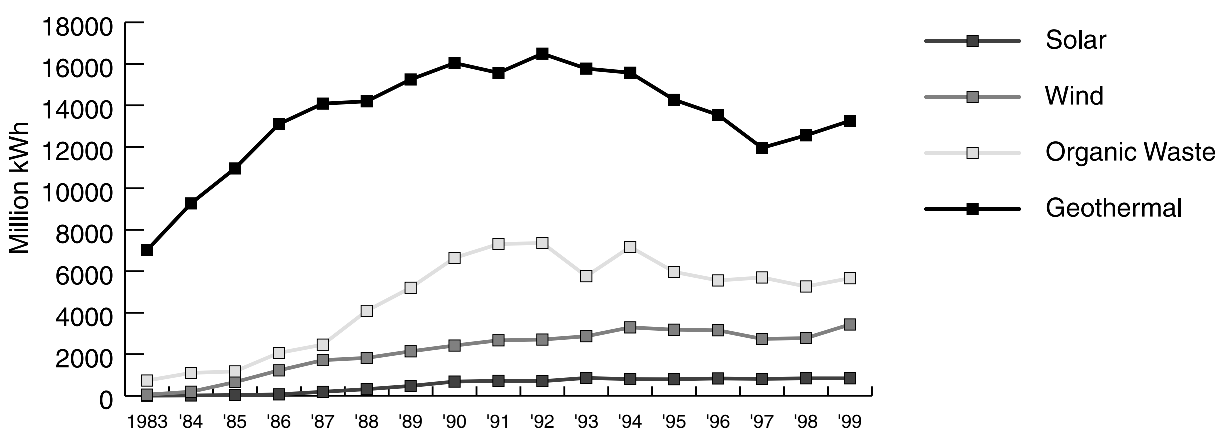
Part III.
Renewable Energy Potential in California

California has an abundance of clean, renewable energy sources. According to CEC data, California produced, on average, over 10% of its electricity from non-hydro renewable sources between 1983 and 1999. The peak of renewable production was 1991, when California produced 14.1% of its electricity from geothermal, biomass, wind and solar energy (see Figure 3.1).

This section provides an assessment of the potential for California to develop additional renewable energy sources, and indicates that the state has the potential to significantly increase total renewable generation, as well as renewables' share of the generation mix. The assessment draws upon other work when possible, either by adapting entire models (in the case of wind) created elsewhere, developing assumptions about market growth (as in the case of PV) and resource availability (in the case of biomass) or basing estimates directly upon other sources (as for geothermal). Table 3.1 summarizes California's existing renewable capacity and potential for capacity additions as identified in this assessment.

This assessment is not a hard target based upon exhaustive economic and resource analysis. Rather, it is a compilation of information intended to demonstrate the promise for further renewable energy development. Indeed, we have found a great need for better, publicly available resource data for wind and biomass, and better market data for PV. Such data should lead to even better estimates of renewable energy potential. In addition, due to the unpredictable nature of current California electricity markets, another assessment at a time when prevailing market

Figure 3.1 Non-Hydro Renewable Power Generation in California, 1983-1999



Source: California Energy Commission Webite. "Electricity in California"
TABLE J-11. CALIFORNIA ELECTRICAL ENERGY GENERATION,
1983 TO 1999: TOTAL PRODUCTION, BY RESOURCE TYPE.
Available at http://energy.ca.gov/electricity/index.html

Table 3.1. Existing and Potential Renewable Energy Capacity in California

Renewable Resource	Existing and Planned		New Potential		Total	
	(MW)	(% share)	(MW)	(% share)	(MW)	(% share)
Wind	2,000	38%	7,300	75%	9,300	62%
Biomass	600	11%	700	7%	1,300	9%
Geothermal	2,700	51%	1,000	10%	3,700	24%
Solar Photovoltaics	20	0.4%	700[a]	7%	720	5%
TOTAL	**5,320**	**100%**	**9,700**	**100%**	**15,020**	**100%**

a. 700 MW is the lower bound estimate for PV.

prices are well understood can better estimate renewables' economic potential in light of their impact on market prices and price volatility.

We do attempt to take into account economic constraints that limit renewable energy's market penetration. For wind, biomass and geothermal, the analysis looks for resources that fall within an "acceptable" price range, with prices ranging from 4 to 9 cents per kilowatt hour (kWh) including tax incentives, while providing one or more of the risk benefits discussed above. PV is a special case, since it can be seen as a retail appliance product rather than a large project suitable only for utilities or large power producers. Thus, its potential is based upon sales trends and customer preferences.

Such prices may be seen as high. But the risk reduction benefits of renewables, as well as their environmental benefits, which are not quantified in this study, justify a prominent role for renewables in the state generation mix.

In addition to California, this section examines renewable energy potential elsewhere in the WSCC region. This is the electric reliability region that encompasses all states from the Rockies and High Plains to the West Coast, including California. States within the WSCC are connected to each other with many transmission lines. Thus, renewable energy development within the WSCC can benefit California greatly, since the state has historically imported power from other Western states that have historically had enough power plant capacity. The following sections discuss each renewable resource in greater detail.

3.1 Wind

Available Capacity and Electricity Supply

Based upon data compiled by Lawrence Berkeley National Laboratory (LBNL), there are at least 26 sites located throughout California that can profitably house wind farms by 2030 if there is a tax credit worth 1.7 cents per kWh, which is equivalent to the current federal production tax credit for wind. Without a production tax credit, none of these sites would be profitable under the assumptions of this analysis. Eleven sites—including most of the sites that now host wind turbines—would meet a target of 4.5 cents per kWh with a tax credit of 0.5 cents per kWh.

LBNL's analysis finds that over 7,000 MW in new, profitable potential is possible in California. The sum of all wind power capacity, including 1,600 MW in existing capacity and 455 MW of planned capacity, is over 9,000 MW.

Some of the sites in this analysis already house turbines; therefore, the results of the study include existing capacity in the state.[49] The size of wind turbines on these sites are different to those in this study—the LBNL study assumes 500-kW turbines, while turbines on the market today range from 750 kW to 1.5 MW. Due to these different sizes, it is difficult to determine the amount of land occupied by existing turbines versus the land covered by the 500-kW turbines in this study. Thus, this study simply subtracts total existing and planned capacity in California today from the total potential capacity reached in the LBNL study.

Additional key assumptions include:

- A production tax credit of 1.7 cents per kWh

- An average 28% capacity factor[50] (i.e., the portion of each turbine's full power capacity that is actually used on average)

- A 4.5 cent per kWh market price for power

- A discount rate of 9%, which implies affordable financing of wind projects (based, for example, on long-term power contracts)

- Finally, the analysis does not examine existing transmission constraints. Such constraints affect all new power plants in California. The state must address its transmission shortages, and so this analysis does not penalize wind power alone for this issue

- The study does not include the potential to increase wind production through repowering on existing sites (i.e., replacing smaller turbines with larger, more efficient ones)

Appendix A lists all of the assumptions of this wind power potential analysis. Table 3.2 summarizes existing, proposed and potential new wind power capacity in California.

Approximately two-thirds (4,500 MW) of the 7,267 MW of new capacity involves additions to three wind farms in California today—Altamont (Contra Costa County), San Gorgonio Pass (Riverside County) and Solano Hills (Solano Country).[51] Tehachapi (Kern County) experiences only modest increases.

Sites other than those that already host wind turbines represent an additional 2,700 MW in new wind power potential. Top sites include Fairmont Reservoir (Los Angeles County), Mount Laguna (San Diego County), Bear River Ridge (Humboldt County) and Potrero Hills (Solano County) that together represent 1,900 MW, or one quarter of new capacity in California.

Table 3.2 Wind Power Potential in California

Category	Total (MW)	Key Sites
Existing Capacity	1,599	Altamont, San Gorgonio, Tehachapi
Proposed As of July 2001	455	Altamont, San Gorgonio, Tehachapi
New Additions to Existing Sites	4,518	Altamont, San Gorgonio, Solano Hills
Development at New Sites	2,749	Bear River Ridge, Fairmont Reservoir, Potrero Hills, Mount Laguna
TOTAL	**9,321**	

Variability

Utility planners frequently cite wind's variability as a substantial challenge to bringing more wind power to the grid. One way to solve variable wind challenges is to rely on a variety of wind farms located on sites that have different wind patterns, thus diversifying the wind resource and ensuring that a minimum amount of wind power will be likely to be available at a given time.

Wind availability from California's top wind farms show loosely related patterns, but ones that are different enough to substantially reduce the overall variation of wind power production at a given time. (See Figure 2.4 in the previous section for a depiction of daily summertime wind patterns on selected wind sites.) For example, in Southern California, Fairmont Reservoir appears to trade off Tehachapi's lower availability in the middle of the day, while Cajon Pass exhibits a fairly steady wind pattern. In Northern California, Bear Ridge's relative consistency in daily availability mitigates the sharper drop in electricity production from Altamont and Solano. Thus, while wind sites throughout California tend to follow similar patterns, diversifying the location of wind projects can smoothen supply.

Wind Resources Elsewhere in the West

In other states, developments in the wind market show that wind power is a lucrative business, attracting substantial demand and investment.

Utilities such as PacifiCorp in the Northwest are developing wind farms due to wind power's price stability (and, in 2001, its lower price compared to natural gas power). PacifiCorp backed a 300-MW wind farm on the Washington-Oregon border, and is also financing projects in the windy Foote Creek Rim of southern Wyoming. Bonneville Power Administration (BPA) issued a 1,000 MW request for wind power proposals. The response was over 2,500 MW of proposals, with almost half the proposed capacity (1,123 MW) in Oregon, 800 MW in Washington state and the rest in Idaho, Montana, Wyoming and Alberta.[52] BPA eventually approved 800 MW of these new projects. BPA, a federal marketer and distributor of power produced by 29 large dams, is in a strong position to develop pumped storage projects where wind and hydropower complement each other to provide a predictable, baseload resource.

While the Rocky Mountain states already have high reserve capacity compared to California and the Northwest, Colorado as well as Wyoming contain promising wind resources that could be developed to offset fossil-fueled power emissions and provide power for export to other states. Colorado's Public Utility Commission required the state's dominant utility, Xcel, to build 162 MW of new wind capacity, in addition to the 57 MW already installed or to be installed by the end of 2001.[53] The PUC reasoned that high natural gas prices made wind a wise investment for Colorado customers. Adding capacity to the Rockies allows the region to export more power to the other states of the WSCC that rely upon it—in particular California.

3.2 Geothermal

Geothermal sources are currently the largest among California's non-hydro renewable electricity sources. Some of the largest U.S. potential for new geothermal capacity is in California and the WSCC region. Geothermal power plants have the highest availability among all types of power plants, with average availability factors of 95% or higher, and greater than 99% for new steam plants at the Geysers.[54]

Geothermal energy technologies are tailored to the heat of geothermal resource fluid being tapped. Geothermal power technologies (both of which are based on liquid or steam) in California include:

- *Flashed steam* technology, which is appropriate when temperatures are above 300°F. This technology is typically the cheapest, but has the most limited resource.

- *Binary cycle* technology, which is ideal when temperatures range from 90°F to 300°F.

According to the U.S. Department of Energy (DOE), the capital cost of both technologies is expected to drop by roughly 20% from 2000 to 2020, and operation and maintenance (O&M) costs are expected to drop by roughly 30%.[55]

California has 25 known geothermal resource areas. Fourteen of these have temperatures of 300°F or greater, meaning they are best exploited using flashed-steam technology.[56] The Geysers area in Sonoma County is the largest resource area, utilizing hot dry steam directly to provide a capacity of over 1,100 MW.

Potential for Increasing Geothermal Power Production

Significant potential exists for increasing geothermal production in California. A representative of the CEC estimates that perhaps 1,000 MW can be installed in California using currently available technology in the next 10 years.[57] Because the Geysers have very high quality steam resources, they can sell power at 3 to 3.5 cents per kWh. Almost all other geothermal fields have lower quality, lower temperature (i.e., less efficient) liquid-dominated resources, with electricity selling for 5 to 8 cents per kWh.[58] Even lower quality resources could be exploited to produce power, but at costs currently exceeding 10 cents per kWh, they would be uneconomic. Technology improvements are steadily lowering the cost of producing geothermal energy from a given resource.[59] Assumptions supporting this 1000 MW estimate are provided in Appendix B. Other estimates for potential U.S. geothermal capacity additions have been made—the most recent estimates based upon current technologies are listed in Table 3.3.

The availability of additional geothermal resources depends greatly on improved technology and cost reductions. The goal of the geothermal industry, with assistance from the U.S. DOE, is to achieve a geothermal-energy life-cycle cost of

Table 3.3 Estimates of Geothermal Potential in the United States, 2000-2020 [62]

Current Hydrothermal Technologies*

Region	Capacity (MW)	Cost	Source
California	1,000	n/a [63]	California Energy Commission (June, 2001)
Nevada	2,000	5-7¢/kWh [64]	Geothermal Policy Working Group (2001)
U.S.	5,000	<3¢/kWh	U.S. Department of Energy (2001)
U.S.	6,500	n/a [65]	USGS, University of Utah, and GEA (1999)
U.S.	10,000	<5¢/kWh	U.S. Department of Energy (2001)

*Binary and flashed steam only, excludes hot dry rock technologies.

electricity of 3 cents per kWh.[60] In the near-term, new hybrid flash/binary systems, or flash and binary systems co-fired with natural gas, are likely to increase the yield of existing geothermal fields without increasing their footprint.[61]

Geothermal Resources Elsewhere in the West

Other states in the WSCC have substantial geothermal resources, both developed and undeveloped. In addition to California, the top states in the United States for geothermal potential are Nevada, Utah and Hawaii, where, in total, over 300 MW are already installed and more are expected to come on-line (see Table 3.4). Additional high potential areas include Idaho, New Mexico, Arizona, Oregon, Washington and Wyoming.[66] Almost all geothermal resources in the contiguous United States are located within the WSCC region (with the exception of some lower temperature (below 100°C) resources in Nebraska and the Dakotas).

There is substantial transmission capacity for new geothermal power throughout the Western region. The Pacific DC Intertie 500 kV DC line rated at 3,200 MW DC line from Celilo, Oregon through Nevada to Sylmar (near Los Angeles) is reported to have as much as 2,000 MW of available capacity. DC equipment and interconnect lines to tie into this may cost 10% to 20% of a new line, making transmission potentially available now instead of having to wait three to five years to construct new lines. Similarly, the Pacific Intertie power lines (which tie into the California/ Oregon Border market node south of Newberry Volcano and north of Mt. Shasta and Glass Mountain, and have historically been used for excess power seasonal regional flows) reportedly have substantial available capacity to transmit geothermal power.[68]

Table 3.4 Geothermal Capacity in the United States, 2001

State	In Operation (MW)	Planned (MW)
California	2,456	200
Nevada	238	79
Utah	39	30
Hawaii	35	0
Total	**2,769**	**309**

Source: U.S. DOE REPiS Database, June 2001[67]

Table 3.5 Current and Planned PV Capacity in the United States

Region	Capacity (MW)	Planned (MW)
California	10.0	11.2
Rest of WSCC	2.6	53.7
Non-WSCC	6.4	4.4
Total U.S.	**19.1**	**69.3**

Source: U.S. DOE REPiS Database, June 2001

3.3 Solar Photovoltaics

Background

Solar energy, especially the more distributed PV, has the potential to provide peak power for California. While solar energy now provides the smallest percentage of California's non-hydro renewable electricity, it has exhibited the fastest growth of any power technology. Between 1983 and 1999, the amount of electricity generated in California by solar energy grew at an average rate of 170% per year.[69] Though the current installed base of PV in California is only about 10 MW, near-term projects already planned or underway are likely to double this figure (see Table 3.5). In fact, the WSCC region currently holds over 85% of U.S. installed and planned PV capacity. However, the potential for increasing PV-powered electricity production in California is limited, primarily by economics and industry development rather than by solar resources.

Future PV Potential

Based on the assumptions mentioned below as well as those detailed in Appendix C, California could reasonably install 700 MW to 1300 MW of PV by 2020. Table 3.6 summarizes the results and the different combinations of market estimates.

To estimate the potential market for PV in California, we make estimates for (1) the total grid-tied PV market from 2001 to 2005, (2) the residential grid-tied PV market from 2006 to 2020, (3) the non-residential, grid-tied market from 2006 to 2020 and (4) the off-grid market from 2001 to 2020.

Grid-tied PV from 2001 to 2005. Based on current market data and trends, we project that California will witness 8 MW in total installations in 2001, with half going to grid-tied PV and the other going to off-grid PV.[70] We also project that the grid-tied portion of the market (4 MW) will grow by 18% per year from 2001 to 2005.[71] This results in a total of 29 MW of PV between 2001 and 2005.

Residential, grid-tied PV from 2006 to 2020. The scenario for rapid growth in residential grid-tied PV features a well-developed PV industry and assertive state policies. We therefore begin this scenario in 2006 to provide time for industry development from 2001 to 2006. For residential, grid-tied PV, we extrapolate from data from a market assessment of Colorado residents conducted by the National Renewable Energy Laboratory (NREL). [72] The NREL survey includes results for consumer preferences for PV at different monthly payments. Using assumptions detailed in Appendix C, we apply these results to California and project that a cumulative 374 MW of residential grid-tied rooftop PV could be installed in California between 2006 and 2020.

Non-residential, grid-tied PV from 2006 to 2020. Our projections for non-residential, grid-tied PV between 2006 and 2020 are based on two assumptions: (1) that the non-residential portion is equal to 25% of the size of the residential, grid-tied market discussed above and (2) that the non-residential portion accounts for 50% of the residential, grid-tied market. The corresponding projections are 75 MW and 187 MW, respectively.

Table 3.6. Projections for PV Capacity Growth in California, 2001-2020 (MW)

Market	Market Penetration Assumptions: Grid-tied low, off-grid low	Grid-tied high, off-grid low	Grid-tied low, off-grid high	Grid-tied high, off-grid high
Residential Grid-Tied 2006-2020, plus all grid-tied 2001-2005	403[a]	403	403	403
Non-residential grid-tied 2006-2020	75	187	75	187
Off-grid, 2001-2020	229	229	747	747
TOTAL (MW)	**707**	**819**	**1,225**	**1,337**

a. Includes 29 MW all grid-tied from 2001-2005, and 374 MW residential grid-tied from 2006-2020.

Off-grid PV from 2001 to 2020. Finally, our projections for off-grid PV are based on two different scenarios: (1) An assumed average annual growth rate of 10% from 2001 to 2020 and (2) an assumed annual average growth rate of 20% from 2001 to 2020. The results are 229 MW and 747 MW, respectively.

Off-grid sales in the United States today are more than twice as large as grid-tied sales. But we've already seen higher growth rates that may well continue in the grid-tied market compared to off-grid. The PV industry is already well prepared to market to and serve the off-grid market (including telecom, pipelines, highway signs, etc.). Thus, industry innovation is likely to provide the most dramatic benefits to the grid-tied market. In addition, if state incentives are to continue, they will most likely target grid-tied markets rather than off-grid.[73]

Recent PV industry growth rates support these projections: between 1995 and 2000, Japan increased PV production more than seven-fold, with an annual average growth rate of over 50% (from 16 MW in 1995 to 129 MW in 2000). With 70% of this production installed domestically, Japan added approximately 90 MW of domestic PV in 2000. Japan encouraged this rapid growth with subsidies targeted at the grid-tied market now in the neighborhood of 120,000 yen per kW ($950 per kW).[74] World production of PV was approximately 200 MW in 1999, 285 MW in 2000, and is projected to top 350 MW in 2001.[75] Given proper market incentives, it is not unreasonable to suggest that California could install the PV capacities given in Table 3.6 as early as 2010.

Potential Elsewhere in the West

The Southwestern United States, including Arizona and southern Nevada, has some of the best solar resources in the country (which maximizes total generation potential) and the highest ELCC in the WSCC region (which maximizes potential value).[76] Developing PV markets in these regions will be important for California. Cities such as Phoenix and Las Vegas are growing rapidly and will add considerable peak electricity demand due to their scorching summers. Integrating PV into the Southwest's burgeoning housing developments can help ensure that these cities do not add to the WSCC's (and California's) reliability challenges.

3.4 Biopower

Biomass power ("biopower") has been the second largest source of non-hydro renewable power in California since the mid-1980s. Biomass plants with almost 600 MW in capacity convert agricultural residues, urban wood waste, mill residues and forest debris to produce 3.4 million MWh per year.[77] Biopower plants in California operate in two distinct regions—the Central Valley (including the San Joaquin and Sacramento Valleys) and the Northern California forests.

Biopower is the only renewable resource that requires a solid or gaseous fuel, though unlike fossil fuels, biomass fuels are those that exist as a byproduct of current human activities that are not primarily for energy purposes in cities, on farmland and in forests.

Like fossil fuel and nuclear plants, biopower plants are capable of producing power on demand—all they require is sufficient fuel. Because biomass plants have much higher potential capacity factors as compared to wind and solar, from a basic electricity production perspective, an installed MW of biomass can provide capacity equivalent to over 2.5 MW of wind power and over 4 MW of solar power.

Future Potential

With resource availability, economics and technical potential in mind, we estimate that about 730 MW of new biopower are feasible for California by 2010 under reasonable technical and economic assumptions (see Appendix D for biopower potential assumptions).[78] This new capacity would produce 5.2 million MWh of electricity, a figure that surpasses the electricity produced by all wind farms in California today.[79] Combining this potential with existing capacity, biopower could offer approximately 1,300 MW to California.

We assume that two-thirds of available, solid biomass (i.e., not including landfill methane) will go to conventional steam boiler plants with fluidized beds, which have an efficiency of 20%. We assume the other third of solid biomass goes to more efficient biomass gasification facilities. Gasification is still in the demonstration phase, and so the capacity from this technology is not expected to come on-line until the latter half of this decade.

Landfill methane powered generation comprises the remainder of potential biopower capacity. These facilities tend to be less than 10 MW in size. They are also located in or near urban areas, making them an important provider of reliable electricity in areas of high demand in case of fluctuations in the supply and price of power from the transmission grid. Table 3.7 shows the contributions of different biomass sources and technologies to the total potential for biomass electricity production.

The mix of biomass resources in the table above implies that biopower plants could be sited in a number of locations throughout California, depending on the biomass resource and its location. According to this resource assessment, both urban wood waste and landfill methane are important sources of biopower, together representing 60% of total biopower potential. These resources are concentrated in cities and towns throughout the state. Agricultural residues are concentrated in the Central Valley, as well as the Imperial and Coachella Valleys of Southern California. Forest residues predominate in

Table 3.7 Potential Electricity Production from New Biopower Capacity in California by Source and by Technology

Technology[80]	Generation (Million kWh)					Total
	Agricultural Residues[81]	Urban Waste[82]	Wood Forest Thinnings[83]	Landfill Methane[84]	All Sources	Capacity (MW)
Fluidized Bed Steam Boiler	620	1,030	380		2,030	291
Combined-cycle Gasification	720	1,200	440		2,360	337
Various				830	830	106
Total Potential	**1,340**	**2,230**	**820**	**830**	**5,220**	**734**
% Generation	26%	43%	16%	16%		

Northern California and the Sierra Nevada mountains in eastern California.

Approximately 130 MW of California's biopower capacity was idle as of late 2001, due to expired or bought-out contracts with Pacific Gas and Electric and Southern California Edison.[85] This idled capacity should be included when examining the cost impact of increased biopower production in California—the total potential discussed above can include this currently retired capacity whose capital costs are partially or entirely paid for, cutting the total cost impact of ramping up in-state biopower.

A production tax credit would place biopower in a healthy competitive position in the California market. Not including landfill methane, and based on the biomass mix assumed in this study (see Appendix D), the average cost of biomass is above $35 per bone dry ton (bdt), which can translate into electricity production prices well above average prices on the California spot market before the electricity crisis. However, a tax credit of 1.7 cents per peak kWh (i.e., the federal production tax credit currently available to wind power and "closed loop" biomass) would reduce biopower prices to a level that should be competitive in the California market. [86]

Biomass Resources Elsewhere in the West

The biopower industry elsewhere is the West is not nearly as active as it is in California. However, according to Oak Ridge National Laboratory (ORNL), 10 Western states could provide 14 million bdt of biomass at $20 per bdt, and over 34 million bdt at $50 per bdt.[87] These totals are between two and three times higher than biomass totals in California as estimated by ORNL. One challenge for biomass development in sparsely populated states is building plants that do not have to pay high transmission costs to ship power to far away demand centers. Operations such as forest thinnings to prevent forest fires would likely occur in remote areas. But nevertheless, there should be opportunities to develop biopower capacity to provide local energy needs, thereby benefiting the entire WSCC including California.

3.5 Pumped Hydropower

While the focus of this paper is on non-hydro renewables, we briefly mention a use of a type of hydropower that can complement other renewables: pumped hydro storage.

Pumped hydro storage is not a form of energy, but offers a way to potentially smooth the output of variable renewables, such as wind. In pumped hydro storage, water is pumped from a lower reservoir to an upper holding reservoir at off-peak electricity. The water is then released through a turbine to create electricity at peak periods, so that it can be sold at premium prices. When there is excess wind capacity, or wind blows at off-peak periods, it may make sense to consider coupling the wind project with a pumped hydro storage facility, assuming the proximity of the wind resource and hydro storage, as well as transmission capacities, are sufficient to make the project feasible. Some pumped storage facilities are completely separate from river systems, lakes and streams, which helps reduce the potential environmental impacts of hydropower. According to the CEC, California has 3,222 MW of existing pumped storage.[88]

Eighteen sites have been licensed by Federal Energy Regulatory Commission (FERC) for new pumped hydro storage development in California, though they have not been developed due to uncertainties in the power market and previous lack of a market for ancillary services. Eleven sites in Northern California have a potential capacity of 3,073 MW and seven sites in Southern California have a potential capacity of 6,080 MW, yielding a total of over 9,000 MW of potential new pumped hydro storage in California (see Table 3.8).[89]

A 1000 MW project underway on the California/Oregon border with a direct interconnect to the AC Intertie has an estimated capital cost of $950 per kW.[90] More generally, the capital cost for pumped hydro storage has been estimated at $546 per kW to $1,050 per kW (1991$).[91]

Table 3.8 Potential for New Pumped Hydro Storage Sites in California, 2001 (MW)

Region	Capacity (MW)
Northern California	3,073
Southern California	6,080
Total	**9,153**

Source: Association of California Water Agencies

Part IV. Policy Options

This section provides a menu of policy options that can be developed or strengthened to diversify the power mix and expand markets for non-hydro renewable energy generation in California and help mitigate financial and environmental risks of power generation in the state.

4.1 System Benefits Charge for Renewable Energy

California is collecting ratepayer funds in a non-by-passable System Benefits Charge (SBC) to support several categories of renewable energy technology development and deployment along with other public benefits. The SBC fund is administered by the CEC. These categories include supporting renewable resources pre-dating the law, new utility-scale renewable resources, new customer-scale renewable resources (especially those using emerging technologies), rebates to customers purchasing a qualifying electricity product with sufficient renewable energy content and a four-year consumer awareness campaign about renewable energy.[92]

In 2000, the SBC expiration was extended from 2002 to 2011. This change provides useful stability to the renewable markets and represents a strong commitment to renewable energy. If the CEC continues to make modifications as indicated by changing technology and customer demand, strong renewables growth is likely.

4.2 Renewable Portfolio Standard

A Renewable Portfolio Standard (RPS) requires retail electricity suppliers to include renewables as a specific percentage of their supply. To promote new renewable development, some states increase the required percentage over time. Alternatively, the state can require a fixed amount of renewable capacity by a certain date. For example, Texas passed an RPS requiring 2,000 MW of renewable energy by 2009. To date, the Texas RPS has been quickly subscribed and utilities are likely to meet that goal several years in advance. As RPS contracts became available, wind developers have competed vigorously for the contracts.

An RPS may also involve a credit trading system, whereby those suppliers who have exceeded their renewable energy requirements can sell extra credits to suppliers who do not meet mandated targets, or keep them and sell them to interested consumers. This trading mechanism provides flexibility so that suppliers with a special ability to install renewables more cheaply than other suppliers can do so and be rewarded. The credit market assures that the public policy benefit of renewable energy is available to generators of the power.[93]

An RPS can work well with the California Renewable Energy SBC. While the SBC is designed to stimulate demand and supply of renewable energy technologies, the RPS articulates a public policy-driven market for the renewable power developed by the SBC. The value of the two programs together would make renewable project investments sounder and, in the long run, enable the CEC to support more projects. California could consider adopting an RPS with an escalating percentage over time to build on the state's past achievements in renewable energy deployment.

An RPS might affect the power acquisition practices of the Department of Water Resources and the new Power Authority to the extent that retail suppliers look to these state entities for wholesale power, including power needed to meet portfolio requirements.

The RPS will tend to support those renewables that are cheapest at the margin. In California's case, wind power would likely benefit the most, with geothermal and biomass also benefiting as the size of the requirement increases. Distributed renewable generation technologies such as PV and small wind turbines are unlikely to benefit as much from the RPS in the near term, due to their higher cost and greater barriers to installation. Because of their reliability benefits, other policies such as a systems benefits fund (discussed above) will play a more prominent role in advanced distributed renewables generation.

If California is to nurture all of its renewable energy options, an RPS alone will not suffice. However, an RPS is an important first step that has spurred rapid, sizeable renewable energy additions in other states.[94]

4.3 Tax Credits for Renewables

Both investment and production tax credits for renewables can play a catalytic role in renewable energy development depending upon the size of the credit. At the federal level, a 1.7 cents per kWh production tax credit for wind power has enabled states with RPSs such as Texas meet their requirements more cheaply. It has also spurred development in states where wind power is close to competitive with fossil fuel sources. However, historically, the federal tax credit alone has not catalyzed new development absent other favorable policies and market trends. Investment tax credits for solar PV can also assist building owners with purchasing and financing their purchases. Unlike tax credits for wind power, tax credits for solar and geothermal energy are in the form of investment tax credit—an upfront credit scaled according to the size of the system (e.g., dollars per kW purchased). Investment tax credits do not incentivize efficient operation and have a checkered history. They may, however, be a far simpler option for small distributed technologies. Either way, by itself, a tax credit is unlikely to spur new installations, due to persistent challenges to finding, installing and financing non-conventional energy options. Instead, enabling policies (such as those described in the section on distributed energy policies below) and substantial private efforts to ease distributed energy purchasing should accompany tax credits.

California's biopower industry has not benefited from the current, extremely limited production tax credit. This tax credit should be restructured in order to be applicable to biopower projects that use urban wood waste, agricultural residues and other sources beyond energy crops, which are not feasible for California today. In addition to this production tax credit, tax credits can also go to purchases of biomass, so that biopower operators can access greater quantities of biomass from sources such as orchard and vineyard prunings as well as forest thinnings.

The federal government has provided tax credits for renewables such as wind, biomass and solar. Current proposals on Capitol Hill include extending the wind production tax credit and expanding the biomass production tax credit to include consumption of residues. Federal investment tax credits for solar PV purchases already exist, though efforts to make it easy for consumers to learn about and access the credit when purchasing solar products are needed.

The continuation of these federal renewable tax credits is essential for renewable energy development in California. The state should also consider complementary incentives that are designed to be additive to the federal benefit.[95]

4.4 Transmission Policies

Renewables such as wind, geothermal and some solar and biopower face the challenge that the best renewable energy resources are not next to major demand centers such as cities. Thus, the cost of transporting power from power plants to consumers may be higher than for natural gas fired generators. This makes policies affecting the cost of sending power over long-distance transmission lines particularly important for those pursuing a more diversified energy future.

The identity of the key agency for drafting and shaping California and Western transmission policies is undecided as of late 2001. Whether it is the California Independent System Operator (Cal-ISO), the legislature or a consortium of firms that own transmission, this key actor should consider the following policies to ensure an affordable renewable energy supply for California:

Avoid pancake pricing. Access to its transmission system should be available for a set of standard prices. The practice of individual companies taking their toll on transactions that cross two or more transmission service territories ("pancaking") inhibits commerce. Instead, region-wide prices that trade off increasing renewables supply against thermal losses should be established to avoid unduly harm to small, remote renewable generators, or unfair subsidy to remote, less regulated fossil resources in other states. It is important that both California and the other stakeholders in the WSCC working on Regional Transmission Organization proposals ensure fair transport of power across different ownership territories.

Open bidding for transmission access. New renewable energy facilities (and new fossil facilities) may face barriers to transmission access to which existing plants get priority access. Allowing renewable energy and other clean energy operators to bid for congested transmission capacity alongside all other plants eliminates unfair preferences for older plants.

Adjusting for deviations in power production. Some variable renewable power systems can accurately forecast monthly output, even an hour ahead in some regions, but day-ahead forecasts still lack predictability. In this way, these sources are similar to a sizeable portion of consumer electric demand. Real-time balancing markets should be established by the system operator to allow generators to buy or sell firm transmission capacity that deviates from the amount reserved in advance, so that generators, including variable generators like wind and solar projects, can use their installed power plant capacity more efficiently. So called Multi-Settlement Systems currently under development by system operators elsewhere in the United States offer a blueprint for addressing this recommendation.

4.5 Distributed Energy Policies

California has a number of policies to lower policy barriers to DG. In some cases, further work is required. The policies are summarized below, with recommendations included where appropriate:

The state approved net metering in 1995 for solar and wind power. Net metering applies to DG that is 1 MW or less in capacity. Original legislation capped the total amount of generation qualifying for net metering effectively at 50 MW statewide. However, the law was recently amended to lift the cap. The legislature should also consider including small, on-site biomass facilities (e.g., methane projects on landfills and farms, anaerobic waste digesters on farms) to the list of qualifying technologies.

California also has standardized interconnection requirements, which streamline the contractual issues that DG owners have to overcome with their local utility. These requirements were established both through legislation and rulings by the California Public Utility Commission (CPUC).

To address the environmental impact of DG options such as diesel generators, Gov. Davis signed legislation in October 2000 that directs the state CARB to adopt a certification program and uniform emissions standards for DG by the beginning of 2003. The legislation requires that certification reflect emissions standards comparable to emissions from "best available control technology" for "permitted central station power plants in California." Based on recent CEC analysis, solar, wind and fuel cells with cogeneration are the only DG options that have lower air emissions than the in-state power plant mix. Thus, while it is uncertain what the final standards will be, if current policy is unchanged, renewables stand to benefit.

California has not yet decided on what kinds of fees utilities can impose on DG owners, including exit fees (i.e., fees for leaving the grid and therefore reallocating grid maintenance costs to the remaining grid-connected customers) and standby fees (i.e., fees that cover the cost to the utility to maintain backup power for the customer in case DG fails). However, a CPUC decision on these fees is pending. Minimizing such fees is essential to maximizing the financial benefits of DG to the owner.

In addition to building upon the above policies, the CPUC should consider designating distributed resource development zones. Such zones would target areas that require substantial near-term investments in the local distribution grid due to an aging power grid infrastructure. In these zones, the state would reward developers of qualifying DG with payments reflecting the cost of avoided investment in the grid, thereby rewarding greater reliability.

4.6 Portfolio Approach

Thousands of individual decisions by utility and generation companies and their regulators will determine if California has a stable, reliable and fairly priced electric system in the future. Traditionally, state regulators could direct vertically integrated electric companies to take a comprehensive system view and diversify power investments, emphasize efficiency, build transmission, or implement other public policy strategies across large geographic areas. A great deal of the renewable energy in California results from past policies along this line. With the present restructured electric industry, California lacks a comparable agent of public policy.

Relying on the fact that most customers are likely to remain on default (or standard offer) service for quite some time, California could opt to provide incentives for specific resource portfolio expectations to the default provider or to the state power authority.

The portfolio approach provides incentives for assembling a mix of long-, medium- and short-term resources, mixes of resource types and financial instruments all designed to balance low cost, price stability and risk. Polices concerning reliability, price stability, DG, renewable energy and energy efficiency also must be considered. Policies should encourage large customer groups to enable decisions that have significant effects on the reliability and price risks facing all consumers, such as energy commodity prices and availability. These customer groups also could spearhead public discussion on appropriate portfolio strategies.

4.7 Market Transformation

Market transformation means changing the behavior of consumers and producers in order to make clean energy technologies more mainstream in the private marketplace. Unlike the renewable portfolio standard, which requires installation of renewable energy by law, market transformation involves strategic actions that educate and offer incentives to private actors to install renewable energy. Some of the programs within the System Benefits Fund administered by the CEC are market-transforming efforts.

For renewables, market transformation is most relevant for DG technologies such as solar and small wind. The California state government, including the CEC, should consider focusing market transformation efforts in the desert Southwest (including the Lancaster/Palmdale area, Palm Springs and the Imperial Valley) and the Central Valley (including the Sacramento and San Joaquin valleys). These regions are likely to add greatly to the state's summertime peak energy demand. Local renewable resources can meet that demand and benefit the grid at the same time.

In particular, the state government should consider working with home, office and warehouse builders in the desert Southwest and Central Valley to identify optimal, economically affordable building designs that incorporate energy efficiency and renewables. Next, both the government and builders should consider strategies to bundle available financial incentives with product offerings to minimize the risk of losing money and to attract consumers.

At the same time, the government should consider a program to educate consumers about the capabilities and benefits of PV (e.g., flatter energy bills throughout the year, reliable power). Such education can attract buyers of solar buildings and interest owners of existing buildings to retrofit with solar.

By working with select builders, the state government can then advertise any commercial successes that may follow (e.g., sold-out subdivisions) to other builders, as well as real estate agents, buildings tradesmen, regional buildings inspectors and other consumers.

Conclusion

California has a broad renewable resource base. The state has pioneered renewable technology development in the past. Going forward, renewables can provide California consumers with the protection offered by fuel diversity. Renewables can also provide important environmental benefits.

This report has analyzed the advantages renewables can provide and has estimated the potential for new renewable development. It has also offered a menu of policy reforms that can assist the development of renewable energy. The actual course of renewable development in California and elsewhere will depend upon consumers recognizing and demanding the benefits renewables can provide. Even then, some policy reforms will be necessary if the full technical potential of renewables assessed in this report is to be realized.

Although it occurred well after the bulk of this report was researched and written, the November 2001 San Francisco Solar Referendum to approve up to $20 million for solar development points strongly towards a California commitment to renewable energy.[96]

APPENDIX A. ASSUMPTIONS FOR WIND POWER ESTIMATES

A number of assumptions underlie the estimates for wind power in California, including:[97]

- The wind data underlying the study was funded and compiled by the CEC and the U.S. Department of the Interior from the late-1970s to the early-1980s. Revised wind data from a measurement effort by CEC and the Electric Power Research Institute (EPRI), expected to be completed in late 2001, may affect the wind power estimates presented herein.
- It is assumed that all wind sites allow a 28% average capacity factor for each wind farm installed. This is highly oversimplified, but since the original study by Lawrence Berkeley National Laboratory (LBNL) upon which this is based assumed very high capacity factors for some sites, this analysis employed a more realistic capacity factor for wind power overall. This in turn affects profitability for each site.
- Wind power operators are assumed to receive 4.5 cents per kWh of electricity, which is within the range of prices on the California spot power market in late 1999 and early 2000, before the dramatic spike in late 2000.
- The total new wind capacity assumes the availability of the federal production tax credit (PTC), which offers 1.7 cents per kWh of wind power generated.
- It is assumed that on ridge sites, 500-kW wind turbines are placed three diameters apart. On flatter areas, they are placed three diameters apart across the wind and eight diameters apart along the prevalent wind. Wind turbines today typically range from 700 kW to 1.5 MW in capacity, though they are sited farther apart from each other than smaller turbines. The implications of greater turbine sizes on the capacity estimates here are uncertain, though they are likely to increase potential capacity. Thus, this assumption alone could underestimate power generation for most sites.
- The data, compiled in 1997, assumes a capital cost of $1,000 per installed kW. Historically, there has been an annual 1.15% reduction in wind capital costs since 1980 when compounded each year. This includes equipment, construction costs, land and permits.
- A number of promising wind sites, such as Strawberry Peak and Mount Laguna, are on public lands—that is, lands owned by the federal government. (Data on the number of sites and the MW they represent was unavailable.)
- Transmission costs from the substation to the grid are $100,000 to $130,000 per kilometer ($161,000 to $210,000 per mile), depending on the terrain (steep slopes, for example, will result in higher costs compared to flat terrain).
- The study does not include penalties related to wind's variability, such as "ancillary services," or power that is delivered at a time in the future in case wind turbines do not run at that time as "promised" in trades involving power delivered in the future. Before the advent of future trading in power, it was believed by many that wind at relatively small shares of total generation (e.g., less than 15-20%) should not be penalized for variability. We do not have a good idea of how California's electricity market will look in the future, and hesitate to include costs related to variability.
- There is a $300,000 fixed hookup charge per wind farm.
- The cost of power lines within the wind farm is $50,000 per kilometer ($83,000 per mile).
- The cost of a substation for a wind farm is $3 million. The study estimates the distance of each wind site from existing transmission lines and then calculates transmission costs for each site. The

study does not account for the nearby transmission lines' attributes, such as their rated capacity to carry power. Note that the study does not include improvements along existing lines, which may be necessary in the future to transport more electricity to different regions in the state. Such improvements will probably incur costs that will affect all power plants, both renewable and non-renewable, coming on-line during the study period.

- Maintenance costs average 1.2 cents per kWh of electricity produced.
- A 9% discount factor is assumed for calculating the levelized cost of producing power.

APPENDIX B: ASSUMPTIONS FOR GEOTHERMAL ESTIMATES

- Much of the estimated 1000 MW of new geothermal energy in California may be in the Medicine Lake/Glass Mountain area, which has large resources that are mostly untapped, as well as additional production in the Geysers area. The actual amount of potential production in the Glass Mountain region will not be known until further physical exploration (drilling) is done.

- Production increases at the Geysers will be primarily through increasing yield from existing wells by pumping waste water from nearby communities into the wells to stabilize the geothermal field, as well as technical improvements in extraction efficiency.

- The 1000 MW estimate assumes use of currently available technology. Technological improvements over the next 10 years may increase the recoverable geothermal energy beyond this estimate.

- The 1000 MW estimate assumes a meaningful production tax credit (such as 1.7 cents per kWh) is available for new geothermal plants.

APPENDIX C: ASSUMPTIONS FOR PHOTOVOLTAIC ESTIMATES

This analysis makes separate assumptions for the grid-tied and off-grid market. Further, we divide the grid-tied market into residential and non-residential for the years 2006 to 2020.

A. Grid-tied market from 2001 to 2006

Finally, we need to estimate the amount of grid-tied PV to be installed in California between 2001 and 2005, based on current market data and trends. We estimate 8 MW in PV sales (both off-grid and grid-tied) this year in California. We assume half goes to the off-grid market and half to the grid-tied market.[98] For the grid-tied market, we assume an 18% annual rate for 2001 to 2005, which is equal to the average annual growth rate for all PV installations in the entire United States from 1996 to 2000. (We do not assume switching rates equal to those for 2006 to 2020 since the PV industry is not yet prepared for the switching rates in the NREL study.) The result is 29 MW of grid-tied PV from 2001 to 2005.

B. Residential, Grid-Tied Market

NREL market assessment assumptions:

- The NREL market assessment hypothetically asks survey participants in Colorado about their willingness to pay for PV systems. All survey sampling was done from May 1998 through July 1998.
- All PV equipment cost assumptions corresponded to actual costs in 1998 in Colorado.
- PV systems were assumed to be grid-tied with no battery storage.
- Electricity usage per average Colorado residence is 600 kWh per month. This amounts to 6,500 kWh per year, which is almost half of the average U.S. annual household usage, but is fairly close to California's average annual usage of 7,200 kWh per year per home.
- The residential electricity price is $0.076 per kWh.
- The market assessment estimates the monthly payments associated with a 3% low-interest 20-year loan. It then associates the number of residential customers who might switch to an electricity mix using grid-tied PV on their roofs with the monthly payment. 4.6% of respondents were willing to purchase PV at the monthly rate.

Our Assumptions:

<u>Industry preparedness.</u> The Colorado survey poses a hypothetical situation to respondents that a PV product is easily available. We make a more stringent assumption that it will take five years for California to adequately develop the manufacturing and distribution pipeline and train enough contractors to install grid-tied rooftop PV in the required amount. This delays our California estimates using data from the NREL by five years. From the present to five years from now, we make different assumptions for the grid-tied market overall (see Part C of this Appendix).

<u>Comparability between Colorado and California.</u> We assume the fraction of California residents responding positively to the offer of grid-tied PV during the period 2006 through 2020 will be identical to the fraction of Colorado residents responding positively in 1998, given similar incentive conditions.

Table C.1. Estimated Residential, Grid-Tied PV Installations in California with a 3% Interest 20-Year Loan, 2006-2020

	Number of Eligible Homes Per Year	Fraction of Homes Adopting PV	Number of Homes Adopting PV per Year	PV System Size (kW)	MW of PV Installed Per Year	Cumulative MW of PV, 2006-2020
Retrofit Homes	575,000	0.023	13,225	1.68	21	321
New Construction	95,000	0.023	2,185	1.68	4	53
Total	**670,000**		**15,410**		**25**	**374**

New versus existing homes. We assume that the fraction of new homes switching to PV will be identical to the fraction of existing residences switching to PV. Because PV may be easier and less costly to install during new construction, the actual switching rate for new construction may be higher than we assume.

Switching rate. We assume the rate of those residents willing to switch to be 4.6%.

Adjustment of switching rate due to siting limitations. We further assume that half of all homes responding positively to the PV offer must be eliminated because the survey respondents did not realize their homes were inappropriate for rooftop PV due to rooftop size, orientation, shading or roof type constraints. This reduces the rate of homes that would switch to grid-tied PV to 2.3% of all homes. By comparison, the Sacramento Municipal Utility District (SMUD) has estimated that 20% of residential rooftops in their service area are appropriate for PV.

Incentives. We implicitly assume 20-year low-interest loans are offered by the utility to customers for purchase of grid-tied PV at an interest rate of 3%. While the 3% loan rate is a strong assumption, we assume no other credits or incentives are applied, such as the current $4.5 per kW CEC buydown incentives currently available. Further, it is likely that as PV prices drop with increasing cumulative production, the 3% loan rate assumption could be relaxed.

Residential homes. We assume PV is only installed on single-family homes. This may underestimate the actual potential for PV installation, as multi-family homes and apartment buildings are excluded.

PV system size. We assume the size of the PV system used in new and retrofit homes is based on the respondent-weighted average of the system sizes used in the NREL study. This weighted average yields a 1.68-kW PV system.

PV For New Homes and Retrofits on Existing Homes

To calculate the number of retrofit homes adopting PV, we assume it would take 20 years to retrofit all homes that wanted to employ PV out of the current 11,500,000 existing homes in California.[99] This means that 575,000 existing homes would potentially be available for retrofit each year. Over the 15-year period from 2006 to 2020, with an assumed switching rate of 2.3%, we estimate that 13,225 homes would be retrofit with PV each year.

To calculate the number of newly-constructed homes adopting PV, we assume a new single-family residence construction rate of 95,000 homes per year in California. Over the 15-year period from 2006 to 2020, with an assumed switching rate of 2.3%, we estimate that 2,185 new homes would add PV each year.

The estimated number of homes adopting PV and the amount of PV installed following from our assumptions are given in Table C.1 below.

C. Non-Residential, Grid-Tied Market

For the non-residential, grid-tied market, we assume that while a smaller fraction of business, schools and city and state facilities are likely to switch to PV under the low-interest loan scenario, the larger electricity demand per each facility that does switch will likely result in a total PV demand equal to

20% to 50% of residential PV demand. This assumption results in another 75 to 187 MW of grid-tied PV installed in California between 2006 and 2020.[100]

D. Off-grid market from 2001 to 2020

While this market is over twice the grid-tied market in the United States today, the development of technology such as inverters and enabling policies for easy interconnection and net metering may lead to a grid-connected market that surpasses an off-grid market.[101] Just as important, if subsidies are to continue, they will most likely target grid-tied markets rather than off-grid.[102]

In addition, higher growth rates are possible in the grid-tied market versus off-grid since the PV industry is most prepared to market to and serve the off-grid market (including telecom, pipelines, highway signs, etc.) and industry innovation may not provide such dramatic benefits compared to grid-tied sales.

For the off-grid market, we assume two scenarios:

(1) The off-grid market represents half of the 2001 market (8 MW) and experiences 10% annual growth from 2001 to 2020. This results in 229 MW by 2020.

(2) The off-grid market represents half of the 2001 market and experiences 20% annual growth from 2001 to 2020. This results in 747 MW by 2020.

APPENDIX D. ASSUMPTIONS FOR BIOPOWER ESTIMATES

A number of assumptions underlie the estimates for biopower in California, including:

Agricultural residues. The total amount of agricultural residues is based upon the historical market high (1.2 million bdt) in 1994 and the possibility of adding over 500,000 bdt of orchard removals to this total, given orchard removal prices of $40 per bdt and higher. Currently, orchard removals represent approximately 15 to 20% of all agricultural residues used in biopower plants in California.[103]

We assume that agricultural residues on average cost $35 per bdt. In 1999, market prices averaged $22.46, with a range of $16 per bdt to $38 per bdt. Some residues, such as nut hulls and fruit pits collected at processing facilities, will cost less than this total, while other resources such as orchard prunings will cost more. On the margin, the most promising new agricultural biomass resource is orchard removals.

Forest thinnings. We assume that forest thinnings cost $50 per bdt. Due to their high collection and transportation costs, forest thinnings are typically the most expensive form of biomass, and industry observers believe that thinnings cannot be economically collected at rates lower than $45 to –50 per bdt. The total bdt assumed under $50 is equal to Oak Ridge National Laboratory's (ORNL) estimate of in-state forest thinnings at $30 per bdt—this downward estimate is based on interviews with California biomass industry representatives in which we found that costs for the resource in California are likely to be much higher than estimated by ORNL.[104]

Urban wood waste. We assume that urban waste wood costs $30 per bdt, and we employ ORNL figures for that market price for California. Urban wood waste is often cheaper than other biomass sources.

Power plant efficiency. We assume that the efficiency is 20% for fluidized bed steam turbines and 45% for combined-cycle biomass gasification plants. The capacity factor for all new plants is 80%.

Energy content of biomass. We assume the following energy values per bdt: 8,600 Btu for urban wood waste, 8,444 Btu for forest thinnings and 8,444 Btu for agricultural residues.

Exclusion of mill residues from new capacity estimates. The biomass mix for new biopower does not include mill residues. It is assumed that no new forest product mills will open in California in the future. The biopower industry's use of mill residues has dropped precipitously since 1993 due to mill closings. Demand for mill residues by the biopower industry alone would not induce more mills to open, or existing mills to remain open.

Exclusion of energy crops from new capacity estimates. We assume that California's biopower future is also unlikely to include new energy crops. According to ORNL, the cost of growing energy crops on agricultural lands is too expensive due to competing, high-value crop markets. (Energy crops plantations do not grow on cleared forest land.)

Other technologies not included in the analysis. Finally, due to budget limits, the analysis does not include a number of promising technologies. One technology is anaerobic digestion, which captures methane from animal waste. It is likely a substantial opportunity for anaerobic digestion exists for cattle, poultry and pig farms in California. This technology is typically less than 5 MW in size and has established a limited market nationwide. Other technologies include biomass for heat engines and advanced recycled combustion systems.

The following is an example of how power production and capacity from forest thinnings channeled to combined-cycle gasification was calculated:

Plant efficiency = 45%
3,412 Btu / 45% = 7,582 Btu/kWh, or the heat rate
*(8,444 Btu/bdt * 2000) / 7,582 Btu/kWh = 2,227 kWh/bdt*
*2,227 kWh/bdt * 197,540 available bdt = 440 million kWh, or 440,007 MWh of power production*
440,007 MWh / 6,989 hours of plant operation = 63 MW of capacity

ENDNOTES

[1] California Energy Commission. Net System Power Calculation, 1999. (Sacramento: April 5, 2000.) Accessed December 13, 2001 at http://38.144.192.166/reports/2000-04-14_300-00-004.PDF
[2] The Arizona region of the WSCC is made up of Arizona, most of New Mexico, the western part of Texas, southern Nevada, and a portion of southeastern California.
[3] Federal Energy Regulatory Commission. *Staff Report on Western Markets and the Causes of the Summer 2000 Price Abnormalities*, November 1, 2000.
[4] California Energy Commission, as cited in Marcus, William and Hamrin, Jan. *How We Got Into the California Energy Crisis*, undated. Available at http://www.jbsenergy.com and http://www.resource-solutions.org.
[5] California Public Utilities Commission's Report to the Governor, August 2, 2000.
[6] Op. cit. Federal Energy Regulatory Commission.
[7] Ibid.
[8] Marcus and Hamrin, *op cit.*
[9] Christopher D. Seiple and Mike Farina. "The Other California Crisis," *Public Utilities Fortnightly,* April 15, 2001, pp. 10-11.
[10] Carbon dioxide, nitrogen oxide, and other emissions from electricity generation are thought to contribute to global climate change.
[11] U.S. Energy Information Administration. *Emissions of Greenhouse Gases in the United States 2000.* (Washington DC: November 2001) DOE/EIA-0573. Available at <ftp://ftp.eia.doe.gov/pub/oiaf/1605/cdrom/pdf/ggrpt/057300.pdf>
[12] U.S. Environmental Protection Agency. *National Air Quality and Emissions Trends Report* 1997, EPA 454-R-98-016 (December 1998), as cited in Adam Serchuk, *The Environmental Imperative for Renewable Energy: An Update*, Renewable Energy Policy Project, April 2000. Available at http://www.repp.org.
[13] Derived from the California Energy Commission's *Database of California Power Plants*, January 2001. Available at http://www.energy.ca.gov/database/index.html#powerplants.
[14] Renewable energy such as wind, solar, and to a large extent geothermal are fuel-free resources that have predictable cost streams through their operating lives. Since a key source of price volatility for current fossil fuel power (primarily natural gas) and hydropower is fuel (or water) availability, fuel-free power sources remove this risk factor. In this respect wind, solar and geothermal serve a role in California's electricity portfolio similar to treasury bills' role in personal investment portfolios. Both investments cost more than other investment options (in the case of T-bills, the comparison would be stocks), but they are essential parts of a well-crafted portfolio due to their low risk. As a result, their lower "yield" (in this case, renewables' higher price of electricity production would be the comparison to T-bills lower yield) may be more than offset by their low price risk, so that Californians may pay a little more for their electricity, but they will be shielded more from price fluctuations that have recently forced the state to pay the second highest electricity rates in the U.S. (Shimon Awerbuch. "Getting It Right: The Real Cost Impacts of a Renewables Portfolio Standard" Public Utilities Fortnightly. February 15, 2000.)
[15] It is uncertain whether renewables can provide a hedging benefit to Californians. A hedging instrument is one whose value moves in the opposite direction from that of another investment. In this case, higher prices for natural gas and lower availability of hydropower would be met soon after by renewables whose price has fallen in relation to the price rise. While renewables over time should continue to drop in price, short-term demand spikes for manufactured renewables such as wind turbines and PV systems might actually increase their cost due to low inventories. Concerted investment in renewables in California should lower this possibility, but it would still exist.
[16] U.S. Energy Information Administration. *Annual Energy Outlook 2001.* Washington, D.C. December 2000.
[17] T. E. Hoff and C. Herig. "Managing Risk Using Renewable Energy Technologies." In *The Virtual Utility: Accounting, Technology & Competitive Aspects of the Emerging Industry*. Shimon Awerbuch and Alistair Preston, editors. (1997), the importance of incorporating dynamic demand growth when accounting for demand uncertainty in a capacity investment economic analysis is explained. When dynamic demands are accounted for, modular systems become more economically attractive.
[18] Ibid.
[19] Graham A. Davis and Brandon Owens. "Renewable Energy Technologies & Real Options Analysis." Presentation to the National Renewable Energy Laboratory. March 8, 2001. Available on the web at http://analysis.nrel.gov/realoptions
[20] Op. cit T. E. Hoff and C. Herig.
[21] Of course, the most popular conventional alternative, the gas turbine, is a relatively modular technology that also can be installed in one year to 18 months while some biomass, concentrating solar and most geothermal can take as long as a typical central station plants to site.

[22] Central station coal-fired plants can take 2-5 years nuclear plants 10+ years—however, the great majority of new plants are gas plants that average 18 months.
[23] In 1999 Enron Wind Corporation installed a 16.5 MW wind cluster near Palm Springs, CA, in just four months, and in 2001 installed a 135 MW wind farm in Pecos County, Texas, in just 7 months. (Source: Enron Fact Sheets—Green Power I and Clear Sky). According to the *Electricity Journal*, it takes about three years to site and build a natural gas plant. (California Crisis: The Best Argument yet for Wind Power. *The Electricity Journal*. April 2001. Vol. 14, No. 3.)
[24] See, for example, Dallas Burtraw. "Cost Savings Without Allowance Trades? Evaluating the SO2 Emission Trading Program to Date" *Contemporary Economic Policy* 14. April 1996. The deregulation of the railroad industry made it cheaper for coal power plants in the Eastern U.S. to import low-sulfur coal from the Western U.S., reducing compliance costs for tighter federal standards for sulfur dioxide.
[25] FERC recently ruled that electricity suppliers bidding into the spot market cannot include the cost of NOx emissions allowances in their bids.
[26] Of course there are at least two other options available to coal plant operators for reducing atmospheric CO2 concentrations. One that has gained the most attention in the past year is the possibility of carbon sequestration, However technologies to capture and reliably store carbon dioxide are not yet cost effective. Another option is to get credit for planting trees, installing renewable energy or energy efficiency, or buying emission permits from other sources on an open commodity market.
[27] Power plant ages obtained from Elizabeth Thompson. *Poisoned Power*. Clean Air Network, 1997. U.S. EPA. "The Mohave Generating Station and Grand Canyon Visibility" Updated June 30, 2000. www.epa.gov/region09/air/Mohave. Viewed 23 October 2001.
[28] Renewable Energy Policy Project and Synapse Energy Economics. *Regulatory Risk: The Cost of Future Environmental Compliance at the Centralia Coal Plant*. Unpublished.
[29] Nate Collamer, ICF Consulting. "Implications of Multipollutant Regulations" Presented to Electric Utilities Environmental Conference, Tucson, Az. January 8, 2001.
[30] Virinder Singh. *Blending Wind and Solar into the Diesel Generator Market.* Renewable Energy Policy Project. Research Report No. 12. (Washington DC: Winter 2001).
[31] Jim Lents and Juliann Emmons Allison. *Can We Have Hour Cake and East It, Too? Creating Distributed Generation Technology to Improve Air Quality*. December 1, 2000. Accessible on the internet at http://www.rapmaine.org/Lents-Allison.pdf. The Regulatory Assistance Project (RAP); "Expected Emissions Output of Various Distributed Generation Technologies" Accessible on the Internet at http://www.rapmaine.org/DGEmissionsMay2001.PDF.
[32] Joseph Iannucci, Susan Horgan, James Eyer and Lloyd Cibulka. *Air Pollution Emission Impacts Associated with Economic Market Potential of Distributed Generation in California*. Prepared for the California Air Resources Board and The California Environmental Protection Agency. June 2000.
[33] For example, in areas meeting Clean Air Act standards, existing power plants may not face any specific control requirements, while those in areas violating the Clean Air Act usually face requirements to install "reasonably available control technologies" (RACT). Similarly, new power plants in areas violating the Clean Air Act face "lowest achievable emission rate" (LAER) standards that are more stringent than the New Source Performance Standards faced by new power plants in attainment areas.
[34] California Energy Commission. *Environmental Performance Report of California's Electric Generation Facilities*. 700-01-001. Sacramento, July 2001.
[35] William B. Marcus, JBS Energy, Inc. "Valuing Load Reduction in Restructured Markets" Viewed October 23, 2001. Available at www.jbsenergy.com.
[36] Rich Cowart and Cheryl Harrington. *Distributed Resources and Electric System Reliability*. West Gardiner, Me: Regulatory Assistance Project, February 2001.
[37] Western Systems Coordinating Council. 10-Year Coordinated Plan Summary, 2000-2009: Planning and Operating System Reliability. October 2000.
[38] Daily peak demand data taken from the California ISO System Conditions web page. Accessed May 11, 2001. http://www.caiso.com/SystemStatus.html
[39] California Independent System Operator, Load comparison summaries, July 1999, May and June 2000, Press release dated May 10, 2000.
[40] California Energy Commission. *Wind Project Performance: 1995 Summary*. Sacramento, 1997. P500-97-003.
[41] Figure 2.4 shows daily summertime wind patterns from key wind sites. They indicate that wind at most sites is most abundant from 3 PM until 3 AM, with some variation. Two of the 7 sites depicted—Bear River and Fairmont Reservoir—have fairly steady wind patterns with small peaks later in the day and into the night. Thus, wind availability overlaps with daily peak demand, though a portion of peak wind availability coincides with periods of low daily demand (i.e., 11 PM to 3 AM). Not all of the electrons from wind farms in California will have peak value during the summer.

[42] PV and Grid Reliability: Availability of PV Power During Capacity Shortfalls. Richard Perez (University of Albany), Steven Letendre (Green Mountain College), and Christy Herig (NREL). 2000. Accessed at http://lunch.asrc.cestm.albany.edu/~perez/ases2001-outages/paper-outage.pdf
[43] Photovoltaics Can Add Capacity to the Utility Grid. Richard Perez and Robert Seals, NY State University, and Christy Herig, NREL. September 1996. DOE/GO-10096-262.
[44] In ten of eleven utility studies, the value of distributed resources that flowed from reduced investment in T&D and from enhanced system reliability exceeded their capacity and energy savings. In Policies to Support a Distributed Energy System. Starrs and Wenger. Renewable Energy Policy Project. http://www.repp.org/articles/pv/3/3.html
[45] Distributed Resources and Electric System Reliability (ibid.)
[46] It's bad, and it'll get worse—POWER DOWN: Electricity blinks out as a baked state seeks relief. *San Francisco Chronicle*. May 9, 2001. John Wildermuth, Eric Brazil, Chronicle Staff Writers. According to data from the California ISO website, actual peak load on May 7, 2001 when rolling blackouts occurred was 33,446 MW, while 12,558 of capacity was off-line at the time.
[47] For a detailed description of the effects of modularity on reliability see op. cit T. E. Hoff and C. Herig.
[48] Profits and Progress through Distributed Resources. February 2000. David Moskovitz. Regulatory Assistance Project (RAP).
[49] See Osman Sezgen, Chris Marnay and Sarah Bretz. *Wind Generation in the Future Competitive California Power Market*. Berkeley, Calif: Lawrence Berkeley National Laboratory. March 1998. The estimates in this report draw upon the work shown in Chapters 1 to 5 in the LBNL study, though with modifications, such as the 4.5 cents per kWh wholesale rate that wind operators receive for their power.
[50] Our assumption of an average 28% capacity factor for wind is slightly more conservative than the 30% capacity factor assumed for new wind projects in California as published in a recent LBNL report (Mark Bolinger, Ryan Wiser, and William Golove. Lawrence Berkeley National Laboratory. "*Revisiting the 'Buy versus Build' Decision for Publicly Owned Utilities in California Considering Wind and Geothermal Resources*" [LBNL-48831: October 2001]) comparing the possible costs of buying wind or geothermal power to the costs of building and operating wind or geothermal capacity under various scenarios.
[51] Existing capacity data from American Wind Energy Association Wind Project Database—California, www.awea.org/projects/california.html, accessed 28 May 2001.
[52] BPA News press release. "Astonishing number of wind generation proposals blows into BPA" April 26, 2001.
[53] *Colorado Wind Power News*. "Public Utilities Commission Orders Xcel to Add 162 MW Wind Farm in Lamar, Colorado." February 23, 2001.
[54] U.S. DOE Geothermal Energy Program: Geothermal Electricity Production. http://www.eren.doe.gov/geothermal/geoelectprod.html. Accessed June 2, 2001.
[55] U.S. Department of Energy (2001)—DOE Renewable Energy Technology Characterizations: Geothermal Hydrothermal. Accessed December 12, 2001 at http://www.eren.doe.gov/power/pdfs/geo_hydro.pdf
[56] California Energy Commission's Geothermal Program (On-line resource). Accessed June 1, 2001 at http://www.energy.ca.gov/geothermal/index.html
[57] Personal conversation with Mr. Pablo Gutierrez of the California Energy Commission's (CECs) Geothermal Program, June 26, 2001. According to Mr. Gutierrez, an estimate posted on the CECs website of 4,000 MW of geothermal energy for California using conventional technology is overoptimistic. Mr. Gutierrez can be reached at 916-654-4663.
[58] U.S. DOE Geothermal Energy Program. Geothermal Power Plants and Electricity Production http://www.eren.doe.gov/geothermal/geopowerplants.html Accessed June 2, 2001.
[59] The cost of generating power from geothermal resources has dropped by about 25% over the past two decades. (Source: Geothermal Facts and Figures. Geothermal Energy Association. Accessed May 31, 2001 at http://www.geo-energy.org/Facts&Figures.htm)
[60] Op. cit. U.S. DOE Geothermal Energy Program.
[61] Personal conversation with Mr. Pablo Gutierrez of the California Energy Commission.
[62] Data sources for Table 3.2 Estimates of Geothermal Potential in the U.S.

- California Energy Commission (2001)—California Energy Commission's Geothermal Program.
- Geothermal Policy Working Group (2001)—Nevada can tap other renewable energy resources: Former state official points to wind, solar, geothermal solutions. Las Vegas Review-Journal. Saturday, February 03, 2001. Accessed at http://www.lvrj.com/lvrj_home/2001/Feb-03-Sat-2001/news/15373589.html
- U.S. Department of Energy (2001)—DOE Renewable Energy Technology Characterizations: Overview of Geothermal Technologies. Accessed May 10, 2001 at http://www.eren.doe.gov/power/pdfs/geo_overview.pdf
- University of Utah (2001)—Energy & Geoscience Institute. Geothermal Energy Brochure (on-line resource). Accessed June 1, 2001 at http://www.egi.utah.edu/geothermal/brochure/brochure.htm

- USGS (1978)—Assessment of Geothermal Resources of the United States—1978, U. S. Geol. Surv. Circ. 790, 1979. Muffler, L.J.P., ed.
- USGS, University of Utah, and Geothermal Energy Association (1999)—Geothermal Gas Price Hedge Power Policy Analysis: New Power Supply At Stable Low Price Without Air Pollution. Accessed June 1, 2001 at http://www.vulcanpower.com/policy_analysis.htm

[63] Cost was said to be "current market price", but was not specifically stated in this estimate. However, no new incentives were assumed in stating that this development could occur within 10 years.

[64] Cost data from personal conversation with John Wellinghoff, consultant to the Geothermal Policy Working Group, December 18, 2001. No production tax credit was assumed. It was assumed that this development could occur within five years.

[65] According to Prof. Joseph Moore, Energy & Geoscience Institute, University of Utah, this estimate is based on technical potential only.

[66] GeoPowering the West (On-line resource). U.S. Department of Energy. Accessed June 1, 2001 at http://www.eren.doe.gov/geopoweringthewest/geomap.html ; Op. cit. The U.S. Geothermal Industry: Three Decades of Growth.

[67] Renewable Electric Plant Information System (REPiS Database). U.S. DOE/National Renewable Energy Laboratory. http://www.eren.doe.gov/repis/index.html. Accessed May 31, 2001.

[68] Geothermal Gas Price Hedge Power Policy Analysis: New Power Supply At Stable Low Price Without Air Pollution. The Vulcan Power Company. Accessed online June 1, 2001 at http://www.vulcanpower.com/policy_analysis.htm

[69] California Electrical Energy Generation, 1983 to 1999 (ibid.)

[70] Based on data from Strategies Unlimited, grid-tied and off-grid PV each represents half of the global PV market. We apply this assumption to California for 2001. Note that some industry observers in California believe that up to 12 MW in installations is possible in 2001, so the baseline figure may be a conservative underestimate.

[71] The 18% assumption is based on average annual growth in PV installations in the U.S. from 1996 to 2000.

[72] Barbara C. Farhar and Timothy C. Coburn. A Market Assessment of Residential Grid-Tied PV Systems in Colorado. September 2000. National Renewable Energy Laboratory. NREL/TP-550-25283.

[73] Data from BP Solar shows that in 2005, non-residential PV will represent 75% of the global grid-tied market. This analysis examines non-commercial grid-tied markets at a range (20-50%) that encompasses the BP Solar estimate of non-residential markets share in the grid-tied market (25%). Incentive programs in Japan and Germany target the grid-tied market. The CEC Buydown program currently focuses on the grid-tied market.

[74] PV News. Vol 20, NO3. 2001. There is a wide range of support in Japanese PV subsidy programs, varying by location from 50,000 yen/kW (Mikata cho, Fukui pref.) to 650,000 yen/kW (Nagoya city, Aichi pref.), or $400/kW to $5000/kW respectively. For more information see Japan's New Energy Foundation, "Examples of Local Governments Implementing or Scheduled to Implement PV Power Generation System Incentive Program" at http://www.nef.or.jp/english/moniter/chihou3.htm

[75] Paul D. Maycock. *PV News*. Vol. 20, No. 3., March 2001 and Vol. 20, No. 12, December 2001. (Warrenton, VA: 2001).

[76] PV and Grid Reliability: Availability of PV Power During Capacity Shortfalls (ibid.)

[77] Gregg Morris. *Biomass Energy Production in California: The Case for a Biomass Policy Initiative*. Golden, Colo: National Renewable Energy Laboratory. 2000.

[78] Among the assumptions are assumed market prices for different biomass feedstocks fed into power plants. The market prices reflect the ability of biopower operators to pay for biomass, and limits the biomass used for power well beneath the physical availability of biomass in California

[79] Wind power contributed approximately 3.2 million MWh in 2000.

[80] Capacity factor is 80% for fluidized bed steam boiler and combined-cycle gasification, and 90% for landfill gas installations.

[81] Based on a potential of 1,750,000 bdt, of which 800,000 bdt is already in use. Potential based on 1994 historical peak use of residues for fuel (approximately 1,250,000 bdt) in addition to 500,000 bdt of orchard removals. Current use based on Gregg Morris. *Biomass Energy Production in California: The Case for a Biomass Policy Initiative*. Golden, Colo: National Renewable Energy Laboratory. 2000.

[82] Based on a potential of 2,606,692 bdt, of which 1,050,000 bdt is already in use. Potential based on Marie Walsh et al. *Biomass Feedstock Availability in the United States: 1999 State Level Analysis*. Oak Ridge, Tenn: Oak Ridge National Laboratory. April 30, 1999, updated January 2000. Current use based on Morris, op. cit.

[83] Based on a potential of 1,231,000 bdt, of which 650,000 bdt is already in use. Potential based on Marie Walsh et al. *Biomass Feedstock Availability in the United States: 1999 State Level Analysis.* Oak Ridge, Tenn: Oak Ridge National Laboratory. April 30, 1999, updated January 2000. Current use based on Morris, op. cit.

[84] Based on estimate by U.S. EPA Landfill Methane Outreach Program. www.epa.gov/lmop/state/california.html. Accessed April 25, 2001.
[85] Op. cit. Morris.
[86] See op. cit Morris for average biomass prices in the California market. Morris associates a biomass price of $23.50/bdt with a fuel price of 2.2 cents/kWh (p. 66). Accordingly, a price of $35.30 would translate into a fuel price of 3.3 cents/kWh. With capital costs for new facilities ranging from 2.5-4.5 cents/kWh (Morris, p. 61), and O&M costs ranging from 2-2.8 cents/kWh (Morris, p. 61), the result would be an electricity cost of 7.8-10.6 cents/kWh. A tax credit of 1.7 cents would reduce costs to 6.1-8.9 cents/kWh for new facilities. Existing, idled facilities have capital costs of 1.4-2.8 cents/kWh, and O&M costs of 2-2.8 cents/kWh (Morris, p. 62). With fuel costs at 3.3 cents/kWh, the resulting range would be 6.7-8.9 cents/kWh. A tax credit would reduce this to 5-7.2 cents/kWh.
[87] Marie Walsh et al. *Biomass Feedstock Availability in the US: 1999 State Level Analysis.* Oak Ridge, Tenn: Oak Ridge National Laboratory, 2000. Includes Washington, Oregon, Idaho, Utah, Arizona, New Mexico, Colorado and Wyoming, Montana and Nevada. Includes agricultural residues, urban wood waste, forest residues and energy crops grown on farmland.
[88] Hydroelectric Power in California. California Energy Commission. Accessed online April 14, 2001 at http://www.energy.ca.gov/electricity/hydro.html
[89] Association of California Water Agencies. Accessed online April 14, 2001 at http://www.acwanet.com/regulatory/value.html
[90] This is the Lorella site—FERC license 11181. Association of California Water Agencies (ibid.)
[91] 1994 Electricity Report (ER 94), Electricity System Planning Assumptions. Appendix A. Western Area Power Administration Central Valley Project. U.S. Department of Energy NEPA website. DOE/EIS-0232.
[92] See Ryan Wiser, Mark Bolinger et al, *Clean Energy Funds: An Overview of State Support for Renewable Energy*, April 2001, for more detail on the California SBC program. Further detail is available at the California Energy Commission web site, http://www.energy.ca.us.
[93] For details on the construction and implementation of the RPS, see Nancy Rader and Scott Hempling. *The Renewable Portfolio Standard: A Practical Guide*. National Association of Regulatory Utility Commissioners, February 2001. Available at www.naruc.org.
[94] Ryan Wiser, Kevin Porter and Steve Clemmer. Emerging Markets for Renewable Energy: The Role of State Policies. *The Electricity Journal*. January/February 2000.
[95] “Double dipping” into both federal and state production tax credits could raise concerns from the Internal Revenue Service. This possibility must be addressed in the design on state tax incentives.
[96] Paul Fenn. Local Power. “San Francisco Voters Pass ‘Solar City Charter’ With Proposition H” (San Francisco: November 6, 2001) Accessed December 13, 2001 at <http://www.local.org/sfproph.html>
[97] See Osman Sezgen, Chris Marnay and Sarah Bretz. *Wind Generation in the Future Competitive California Power Market*. Berkeley, Calif: Lawrence Berkeley National Laboratory. March 1998.
[98] Based on data from Strategies Unlimited, grid-tied and off-grid PV each represents half of the global PV market. We apply this assumption to California for 2001.
[99] According to the EIA *1997 Residential Energy Consumption Survey*, California had 11,500,000 single-family homes in 1997.
[100] Data from BP Solar shows that in 2005, non-residential PV will represent 75% of the global grid-tied market. This analysis examines non-commercial grid-tied markets at a range (20-50%) that encompasses the BP Solar estimate of non-residential markets share in the grid-tied market (25%).
[101] Data from Paul Maycock. “The PV Boom: Where Germany and Japan lead, will California follow?” Renewable Energy World, Vol. 4, No. 4 (July-August 2001).
[102] Incentive programs in Japan and Germany target the grid-tied market. The CEC Buydown program currently focuses on the grid-tied market.
[103] Op. cit. Morris; Gregg Morris. Personal correspondence, June 5, 2001; Robert Judd, California Biomass Energy Alliance. Personal correspondence, June 6, 2001.
[104] Marie Walsh et al. *Biomass Feedstock Availability in the United States: 1999 State Level Analysis*. Oak Ridge, Tenn: Oak Ridge National Laboratory. April 30, 1999, updated January 2000.

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REPP receives generous support from the U.S. Department of Energy, the Energy Foundation, the Joyce Mertz-Gilmore Foundation, and the U.S Environmental Protection Agency, the National Renewable Energy Laboratory (NREL), the Bancker-Williams Foundation, the Oak Foundation, the Surdna Foundation, and the Turner Foundation.

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