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CALIFORNIA'S SOFT RENEWABLE PORTFOLIO STANDARD

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INTRODUCTION

Across the world, there is a growing commitment to power from renewable sources. The benefits are obvious and well known: reduce reliance on fossil fuel consumption and thereby achieve both lower greenhouse gas emissions and greater local control over the power industry. The main challenge, however, is that private costs of green power production remain higher than for power from conventional resources. There are numerous policy approaches that can be used to overcome this competitive disadvantage, one of which is to legislate that power from renewable sources is to constitute a minimum percent of all power sold to end users, i.e., a Renewable Portfolio Standard (RPS). Such standards have previously been reviewed in general terms by Rader and Norgaard (1996), who motivate the RPS on efficiency grounds given market imperfections. Rader (1998) points out that it is unlikely that restructured electricity markets will enhance the market position of renewable sources of electricity. Accordingly, many states and countries that have gone through restructuring to enhance competition have adopted an RPS. Berry and Jaccard (2001) review implementation issues in several countries and US states that have taken this route.

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The purpose of the present paper is to characterize in relatively straightforward terms the economic nature of the very complex RPS recently enacted by the state of California[1]. The essence of the RPS legislation is that it creates a reliable market for green power (a 20 percent market share by the year 2017) and combines this with a subsidy source that has been available since 1998. The historical origin and nature of this policy are described in the paper. Given a set of benchmark numbers and a simple simulation model, the likelihood that the RPS will be achieved is assessed and the policy is evaluated in terms of economic efficiency.

1. BRIEF HISTORY OF GREEN POWER IN CALIFORNIA

The California green power industry and the 2002 RPS have their roots in the landmark federal Public Utilities Regulatory Act of 1978 (PURPA). Prior to this Act, the power system in the U.S. consisted mainly of regulated, integrated monopolies controlling the generation, transmission and distribution networks. PURPA started the still ongoing process of breaking up this rigid system by allowing small independent producers and co-generators ("Qualifying Facilities") access to the distribution network on terms and conditions based on the concept of avoidable costs. The state of California was the most aggressive of all states in expanding green power by offering extremely favorable terms and conditions to green, independent producers in the 1980s (see Figure 1)[2]. As natural gas and power prices started declining in the mid-1980s, green power producers were sheltered by long-term contracts with high prices. By the time California became obsessed with restructuring and deregulation in the mid-1990s, the state had the largest share of non-big hydro, green power of any state. The segment has since been hammered, however, by a series of events that have played themselves out over the last ten years.

In the 1990s, the expensive long-term green power contracts started to expire and independent producers were paid the equivalent of the much

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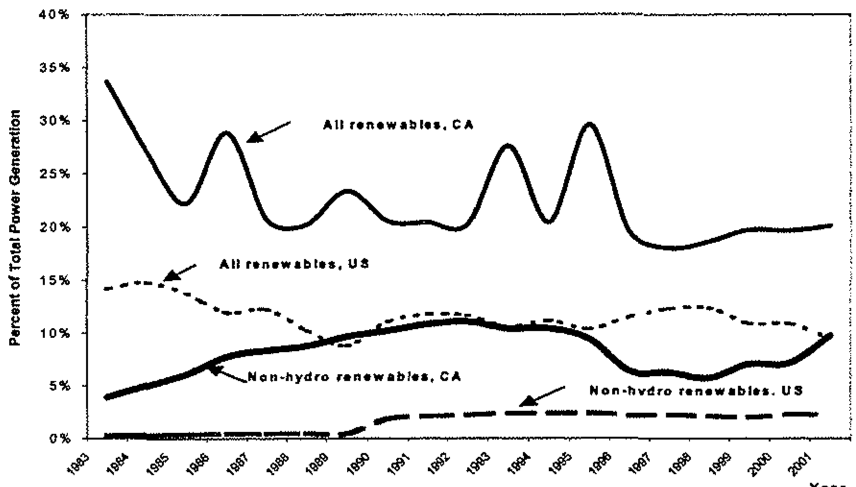
[1] California Senate Bill 1078 signed into law September 12, 2002. The California Bill uses the plural Renewables rather than the more common Renewable Portfolio Standard. The existence of a financing constraint implies that California's version should be labeled a "soft" RPS in contrast to the rigid, conventional RPS. This paper follows the California convention of excluding big hydroprojects from the notion of green power.

[2] The largest distribution utility in California, Pacific Gas and Electric (PG&E) - also the largest in the U.S.- paid average prices in the range of 5.3 - 7.4 cents/kWh through 1985 to Qualifying Facilities.

lower, short-term avoidable cost[3]. Meanwhile, the state's policymakers focused on restructuring the power industry and sought to resolve the green power industry's challenges as part of that process rather than through an isolated intervention into the green power segment. Combined with low prices, this policy inaction meant that the green power industry in California went on the decline.

Figure 1: Green Power Market Share in the U.S. and California



Sources: The Energy Information Administration and the California Energy Commission.

The legislation that mandated the restructuring of California's power industry (AB 1890) sought to jump-start the green power industry again by giving it a favored place within a competitive retail market. Green producers would receive subsidies and direct retail buyers of green power would receive a discount. The financing mechanism would be a "public goods" charge on power sales to be managed by the California Energy Commission (CEC) subject to criteria and oversight by the Legislature. Policymakers believed this approach would cause rapid expansion in green power production. A goal frequently cited by the Governor and the executive branch was a green power market share of 17 percent by the year 2006.

The program became, however, another casualty of the California electricity crisis. A large portion of the subsidy funds initially went to

[3] Excluding a price peak in late 1996 and early 1997, PG&E's average prices to green producers declined to the range of 2-4 cents/kWh through the 1990's.

existing green power producers to keep them in business when prices were low. When the California wholesale prices exploded starting in the middle of the year 2000, it was no longer necessary to subsidize existing producers, but distribution utilities eventually became insolvent and green producers went unpaid for months. Funds earmarked for new green power capacity went almost unused under these conditions. From 1998 through March 2002, only 201MW of new, nameplate capacity came on stream under the CEC program.

The California Public Utilities Commission (CPUC) started providing relief to existing green power producers in June, 2001, by offering five-year contracts to existing green power producers at 5.37 cents/kWh[4]. By late 2002, 68 percent of Qualifying Facilities had taken this option. The CPUC, furthermore, ordered the utilities to start making partial payments for past supplies. The Commission started to provide relief to potential new producers of green energy in August 2002 by requiring distribution utilities to solicit bids from new green producers in the amount of 1 percent of their 2003 electricity needs[5]. The CPUC used the same 5.37 cents/kWh price and required that contracts of 5, 10, and 15 years to be offered. In effect, this decision is consistent with the RPS legislation, which by then had been passed by the Legislature but had not been signed by the Governor.

CALIFORNIA'S RPS: GENERAL CHARACTERISTICS

The September 2002 RPS legislation set a challenging goal for the directly affected parties (regulators, distribution utilities, and green power producers) in an already extremely complicated power market. A series of implementation issues were resolved by the lead agency, the CPUC, in a June 2003 decision[6]. The description below focuses on the broad outline of the RPS and, in particular, the features and limitations of the legislation that provide its unique California flavour.

The legislation requires each of the state's three privately owned distribution utilities (Pacific Gas & Electric, Southern California Edison, and San Diego Gas and Electric) to reach a 20 percent green power market share by the year 2017. This is to be achieved through annual 1 percent

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[4] CPUC Decision 01-06-015. The price defined in this decision, 5.37 cents/kWh, is consistent with PURPA avoided cost methodology as refined to apply to California's particular conditions in AB1890 of 1996, the California power market restructuring bill. When this decision was made, PG&E's short term avoided cost for qualifying facilities was 5.772 cents/kWh.

[5] CPUC Decision 02-08-071.

[6] CPUC Decision 03-06071 June 19, 2003

increments with limited opportunities for make-ups in the event of a shortfall. Under current implementation rules, distribution companies are not allowed to trade with each other when some achieve the target and others don't, but the CPUC has the authority to implement such a trading system in the future. There is no current mechanism to force utilities to contract for more than the 1 percent annual quota or to pay more than a fair market price for green power.

Producers of green power will receive 10, 15, or 20-year contracts from the distribution utilities with standard terms and conditions and a fixed price. Subsidies beyond this price are available if necessary to increase green power supplies to reach the RPS target.

The Legislature set the 20 percent target for 2017 achieved with 1 percent annual increments as a minimal target. A subsequent Energy Action Plan entered into by and between California's three energy regulating agencies calls for the 20 percent target to be reached as early as the year 2010 and remain at that level thereafter. This scenario is discussed in the Appendix[7].

Green power capacity and corresponding long-term contracts are to be developed through a competitive bidding process. The outline of the process is illustrated in Figure 2 and described below.

Every year, the distribution utilities are to develop a resource assessment plan and specify the added green power needed to achieve the RPS, i.e., the Annual Procurement Target. Accordingly, the utilities will issue requests for proposals from potential developers of green power based on 10,15, and 20-year standard contracts. The proposals from potential suppliers generate the supply schedule in Figure 2, one schedule for each distribution utility[8].

How is the cut-off point on the supply schedule to be determined? The CPUC will define current "competitive benchmark" prices (sometimes also called "market price referents") applicable to the bidding process. These will be developed by the CEC and based on estimates coming from simulating the total, private cost of power from the most competitive, alternative source, e.g., a combined-cycle, natural gas plant for base-load

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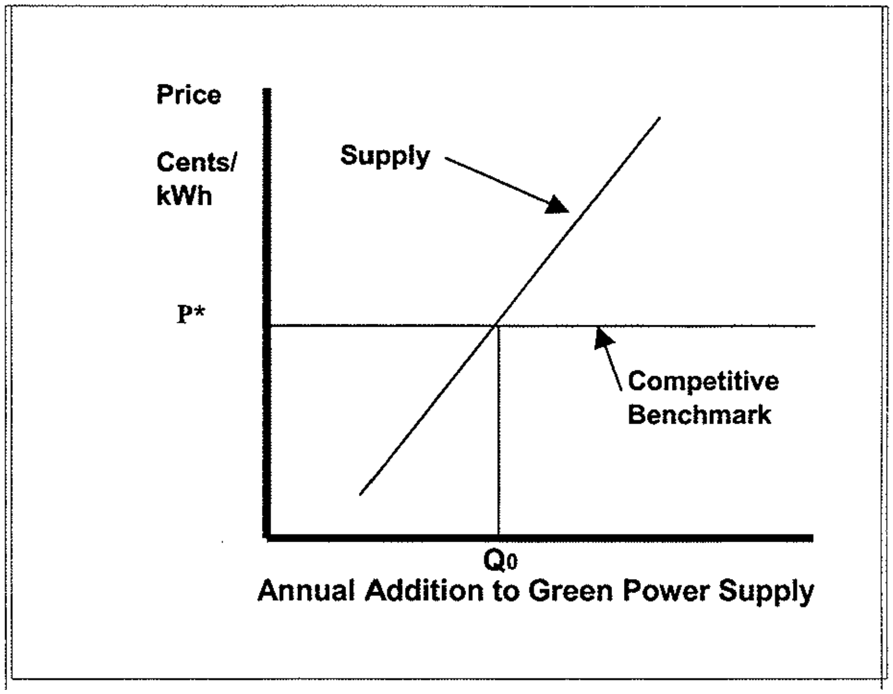
[7] California Consumer Power and Financing Authority (CPA), California Energy Resources Conservation and Development Commission (CEC), and California Public Utilities Commission (CPUC) (2003).

[8] This paper uses the simplification that there is only one product that is being offered. In the implementation rules, there is a distinction between three products: as-available, base-load and peaking power. The utility's final ranking of proposed projects is to reflect integration and transmission costs. In essence, the legislation as well as the implementation rules are clearly aimed at selecting the least cost portfolio of green power projects.

supply. In effect, the competitive benchmark price is based on private cost conditions outside the green power industry. This price, which acts like a price ceiling to the distribution utility, is revealed to bidders after the bidding process is over. In Figure 2, this price is indicated as P^*.

Figure 2: Illustration of Bidding System.



If the utility receives sufficient bids below the competitive benchmark price to fulfill the RPS, the utility proceeds to contract with the suppliers at the bid price and the bidding process ends until additional green power is needed. The utility has thereby met its responsibility. Graphically, this means that Q_0 is greater than or equal to that required by the Annual Procurement Target and therefore with the RPS. If the supply bid at or below the ceiling price is inadequate to meet the RPS, subsidies will be needed. (Graphically, Q_0 is less than the RPS target.) Providing the subsidy is not the responsibility of the utility; it is the responsibility of the CEC. The funds will come from a "public goods charge" imposed on all the distribution utilities' customers and administered by the CEC. These funds are needed to support suppliers on the supply schedule above the competitive benchmark price, P*. If the funds from the "public goods charge" are insufficient to cover the gap between the RPS requirement and the green power volumes accepted by the utilities, the RPS will not be met.

This arrangement differs from the usual RPS in that it has two "soft" spots that make it possible that the RPS will not be achieved. The first soft spot is that distribution utilities will not offer potential producers more than the competitive benchmark price contained in a standard contract defined by the CPUC. If this is insufficient to meet the RPS, the utility is off the hook provided it has been prudent in the process. The second soft spot is that the funds from the "public goods charge" may be inadequate to make up for the difference between the RPS requirement and the green power contracted for by the utilities. If it is, the CEC is off the hook, and the RPS is not met.

There are two other noteworthy features of the process. First, it leads to some degree of price discrimination between the various green power suppliers that are awarded contracts. The intent is to minimize the cost of the accepted portfolio of projects. Whether this price discrimination will be successful or not for that purpose depends on bidder strategies. Over time, they are likely to develop good estimates of the competitive benchmark price in advance of the process, the rate of subsidies available, and the degree of competition in the bidding process. If so, this should to lead to a reduction in bid spreads.

Second, and from an administration point of view, a simpler approach would be to offer the competitive benchmark price plus some subsidy reflecting the added, social value of green power (a "fixed, feed-in tariff"). California is not taking this approach apparently because of a preference for the potential cost reduction associated with price discrimination and a preference for some administrative control of the final selection of winning bids.

Whether or not the RPS will be met depends critically on four parameters:

the total amount of funds available from the "public goods charge";
the volume of green power necessary to meet the RPS;
the cost of producing power in the competitive generation market; and
the cost of producing power from renewable sources.

Estimates of these parameters are developed next, and they are used in the simulation and evaluation that follow thereafter.

BENCHMARK NUMBERS AND SIMULATION

The Financial Constraint.

Legislation passed in 1997 (SB 90) and continued in 2002 (SB 1038) mandates collection of $135 million per year through the year 2012 to fund the CEC's renewable energy program. These funds are distributed through five accounts: New Renewables (50%); Existing Renewables (20%), Emerging Renewables (15%), the Customer Credit Fund (10%) and the remainder in the Consumer Education Fund (5%). For discussion purposes below, it is assumed that all but the 5 percent going to Consumer Education will be available for future green capacity building under the RPS. The need to fund existing renewables under this program has been sharply reduced or eliminated as these have been offered, and most have accepted, long term, fixed price contracts as discussed above. Furthermore, the direct sales market for green power has also substantially vanished with the California energy crisis. The estimated annual, financial constraint on the RPS is therefore 95 percent of $135 million, equivalent to $128 million. Below, it is assumed that this financing will continue beyond the currently mandated year 2012 and through 2017.

Green Power Additions Under the RPS.

The three distribution utilities currently supply 82 percent of California power consumption. The CEC (2003a) provides forecasts for future sales through the year 2013. These have been employed and extended in Table 1. According to CEC (2001), the state's green energy production amounted to 31,978 GWhs in the year 2000, equivalent to 12.1 percent of consumption. In forecasting green power needs, the following assumptions are made:

> The percent of green power in the combined utility portfolio is the same in the year 2000 as for the entire market (i.e., 12.1 percent).
>
> This percent is assumed constant in 2001 and 2002 due to very small additions to green power capacity as discussed above.
>
> Implementation proceeds smoothly such that the combined utility portfolio's green power sales increase by 5.4 percent per year to achieve the 20 percent market share goal by 2017.

Table 1 shows the production forecast based on these assumptions.

Table 1: Green Power Production

Year	All Power from Utilities		Green Power from Utilities		
	GWhs	Percent of All End Use	GWhs	Percent of Utility Sales	Subsidized GWhs
2001	207,162	82%	25,142	12.1%	
2002	211,558	82%	25,675	12.1%	
2003	216,051	82%	27,069	12.5%	1,394
2004	220,641	82%	28,538	12.9%	2,863
2005	225,332	82%	30,088	13.4%	4,413
2006	230,125	82%	31,721	13.8%	6,046
2007	234,595	82%	33,443	14.3%	7,768
2008	239,152	83%	35,259	14.7%	9,584
2009	243,799	83%	37,173	15.2%	11,498
2010	248,536	83%	39,191	15.8%	13,516
2011	253,366	83%	41,318	16.3%	15,643
2012	258,291	83%	43,561	16.9%	17,886
2013	263,312	83%	45,926	17.4%	20,251
2014	268,432	83%	48,419	18.0%	22,744
2015	273,652	83%	51,048	18.7%	25,373
2016	278,974	84%	53,819	19.3%	28,144
2017	284,401	84%	56,880	20.0%	31,205

Source: CEC (2003a) and projections by the author.

The Competitive Benchmark Price.

The CPUC has used 5.37 cents/kWh on two recent occasions for the purpose of long-term contracts for renewable facilities using avoidable cost as a rationale. For the purposes of the RPS, the competitive benchmark ought to be the long run avoidable cost, rather than the short-term avoidable cost rooted in PURPA. The alternative to green power these days is combined cycle natural gas. Levelized, full cost for new combined cycle plants should therefore be the competitive benchmark. The CEC (2003b) has recently estimated this to be at 4.58 cents/kWh conditional on a gas price forecast starting at $4.55 presently, declining to $3.94 in 2005, and then increasing smoothly to $5.83/MMBtu in 2013. The fuel use in the California avoidable cost formula is slightly higher than 9,000 Btu/kWh. This implies that every one dollar shift in the future gas price schedule gives a .9 cent/kWh change in the competitive benchmark price in the same direction. Given these numbers, it is reasonable to assume that the CPUC will initially determine a competitive benchmark in the 4.5-5.5 cents/kWh range and which is likely to change later if the gas price forecast changes.

The Cost of Producing Green Power.

The CEC (2003b) estimates the costs for various renewable generation technologies. These are generally consistent with cost estimates from other sources. Wind and geothermal resources are reasonably close to the likely competitive benchmark, but solar and fuel cells remain very expensive at double to four times the benchmark price[9].

Using these benchmarks, a simple simulation model was defined to evaluate whether the RPS target is reasonable, given the financial constraint, and how sensitive the market share achievement is to the price of natural gas. The simulation model is explained in the Appendix.

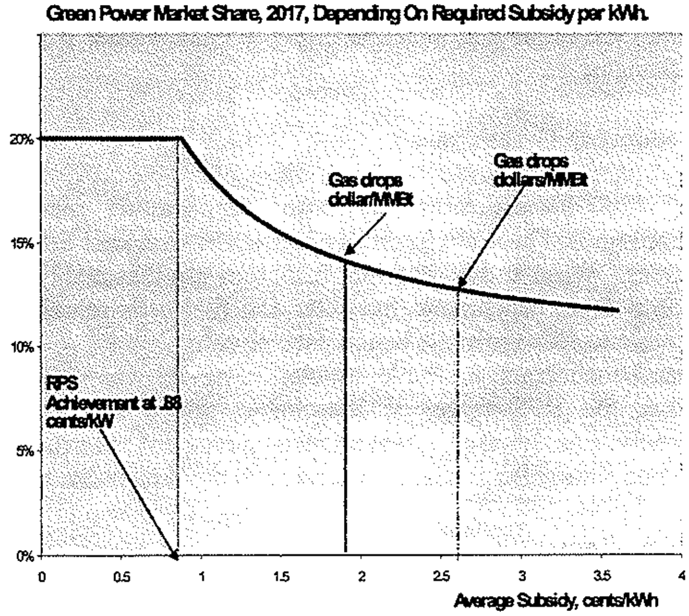
RPS Goal Achievement.

Given the total subsidy amount available and the assumed production profile for additional green power that achieves the 20 percent target in 2017, there is .88 cents/kWh of subsidy available to new producers of green power. This is the amount that can be added on top of the competitive benchmark for every added kWh of green power between 2003 and 2017. Figure 3 shows that the target 20 percent is achieved as long as the required, average subsidy stays at or below .88 cents/kWh. If the required, average subsidy is higher than .88 cents/kWh, the percent market share for green power declines. If the benchmark is set somewhere between 4.5 and 5.5 cents and green power producers receive a .88

[9] The CEC (2003b) estimates in cents/kWh are: Geothermal (flash) 4.71; wind 5.44; and geothermal (binary) 7.64. The cheapest fuel cell technology is at 9.10 cents and the cheapest solar at 14.99 cents.

cents/kWh subsidy, the total cost of green power from wind and flash geothermal are covered and the subsidy amount stretches to reach some binary geothermal. It is unclear how much of these resources are available at the estimated costs. Given the current outlook for key parameters, the conclusion is therefore that California has a fair chance of achieving its RPS by 2017 if there are sufficient volumes of wind and geothermal available at the CEC (2003) estimated cost. For convenience, this scenario, which implies goal achievement, is referred to as the base case below.

Figure 3.
Green Power Market Share, 2017, Depending On Required Subsidy per kWh.



The degree of market share achievement is, however, remarkably sensitive to the price of natural gas. If the forecasted schedule for the price of gas shifts downward by one dollar below the base case, it will be necessary to add another .9 cents/kWh of subsidy and thus the average subsidy goes from .88 cents/kWh to 1.78 cents. In that case, the constraint on total financing only allows 14.5 percent market share achievement in 2017. If gas drops by $2/MMBtu, goal achievement drops to 12.6 percent, which is just about where it is at present. The tradeoff between required subsidy and market share in 2017 is shown in Figure 3.

EVALUATION

The main difference between the soft California RPS and the common, rigid RPS is the financing constraint, which makes goal achievement conditional on relative prices. A rigid RPS achieves the goal irrespective of costs. In terms of economic efficiency, the California RPS is superior when viewed from both the cost and the benefit side[10].

First, consider the cost side. The California approach is superior because it follows the general principle that the purchases of two close, but not identical substitutes should depend on their price ratio. By paying a subsidy, California has already expressed its willingness to tweak the price ratio in favor of green power. When the price of gas drops, however, it becomes more expensive to achieve greenhouse gas emission reductions and greater local control over the power market – the two main benefits of green power that the subsidy buys. Thus the logical conclusion is to demand less green power and use resources elsewhere, perhaps to achieve the same goals. California's soft RPS automatically achieves this since green power expansion is slowed down through the financing constraint. The rigid RPS ignores price ratio changes and reaches the target irrespective of opportunity costs.

Second, consider the benefit side. The rigid RPS treats every percent increase in green power market share as equally important up to the point where the RPS is satisfied. This may be appropriate considering the benefit of greenhouse gas emissions reductions. On the other hand, the benefits of greater diversification of fuel sources and more local control over the power industry most likely decline with the size of the green power industry. By imposing a constraint on subsidies, California is certain to achieve the first few percentages of green power market share gains, but the last few percentages are at risk depending on how expensive they are in terms of subsidy requirements. This prioritizing is desirable if the social benefits of market share gains decline.

From an economic efficiency perspective, the California soft RPS can be improved in a couple of ways.

First, there is the question of what happens if the average subsidy needed to achieve the 20 percent RPS is less than what is available (in Figure 3: less than .88 cents/kWh). In this case, the financing constraint is not binding and surplus funds accumulate. The discussion above assumes that these surplus funds are saved and used for non-green power purposes. This creates the flat portion of the target achievement line in Figure 3. But

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[10] The reader will recognize that the implicit analogy for evaluating efficiency is consumer choice with a budget constraint. Specifically, it is about the case when relative prices change.

it is inefficient to stop buying additional green power when it becomes cheaper. Since the benefits of green power are unaffected by the decline in costs, the rational choice is to keep buying more green power to the full extent of the budget constraint. In terms of Figure 3, this would continue the strictly convex portion of the curve up towards the vertical axis. The legislation that created the "public goods charge" and determined its uses is in effect through 2012. At that time, the state can let it expire or remain in effect. At present, there is no provision for the use of surplus funds – except to enhance the green power industry. In that case, it is unclear whether California really has a soft RPS or just a green power policy with a financial constraint. If it is the latter, two things follow: (1) the significant element introduced by the RPS legislation was a reliable market outlet for added green power, which had been missing in California for a number of years; and (2) California has chosen a more efficient approach than the soft RPS.

A final observation on efficiency consideration is that an RPS - whether of the soft or the rigid type - ignores that demand side policies to encourage greater efficiency and conservation are great substitutes for green power. As the subsidy requirement increases up along the supply schedule for green power, it becomes relatively cheaper to subsidize demand reductions rather than the green power segment on the supply side. This substitution possibility driven by comparative costs should be integrated into any green power program to enhance the economic efficiency of that program. Current policies in California show that the state is well aware of this opportunity.

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APPENDIX

The Simulation Approach.

The California RPS comes with a financial constraint backed up by a "public goods charge" on all final buyers of electricity. The total amount generated by this charge represents a budget constraint, B, on the subsidies. The focus of the paper is on the average subsidy per kWh, s^*, considering all qualifying projects and all years. Let Q_t denote green power deliveries in kWh in year t (t = 2004,..., 2017) that potentially qualify for subsidies. The following accounting identity is used:

$$B = s^* \sum Q_t$$

This simply states that the total budget constraint, when binding, is the product of the average subsidy and the sum of subsidized green power production from 2004 to 2017. A time path for green power production that satisfies California's RPS was given in Table 1 together with the an estimate of the annual quantities of green power that qualify for subsidies. With an estimate of B and $\sum Q_t$, it is straightforward to calculate s^* as .88 cents/kWh as the ratio between the two. The calculated s^* is the average subsidy which (1) causes the budget constraint to be binding under the assumptions used in this paper, and (2) allows the RPS to be fulfilled.

Next, suppose the required subsidy is less than s^*. Everything else being constant, the budget constraint is not binding, the RPS target is achieved and the solution ends up on the flat portion of the curve in figure 3.

On the other hand, assume the required subsidy increases by a factor k (k>1) perhaps because natural gas prices decline. Then the budget identity can be written as

$$B = (ks^*)\,(1/k)\ \Sigma Q_t$$

or

$$B = (ks^*)\,\Sigma(1/k)\,Q_t$$

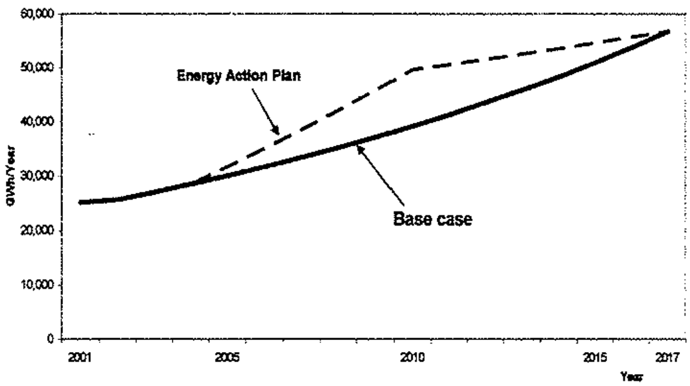
under the assumption that green power sales are affected in the same proportion in all future years. This allows calculation of a revised estimate for green power in the year 2017, which can then be employed to calculate green power market share in that year. The simulation of the sensitivity of the RPS goal achievement with respect to the price of natural gas takes advantage of the fact that k varies predictably with the price of gas. Specifically, every one dollar change in the gas price leads to a .9 cents/kWh change in the required subsidy.

Example: Suppose the price of natural gas decreases by $1/MMbtu from the base case scenario. This implies a .9 cent/kWh increase in the required, average subsidy for green power, raising the subsidy level from .88 cents to 1.78 cents. This defines k in the expressions above as 2.02. The implication is that available funds can only subsidize about one half (1/2.02) of the green power in the base case scenario, i.e., about one half of the quantities in the rightmost column of Table 1. From that, it is easy to calculate total green power in the year 2017 as a percent of total power sold by the utilities in that year.

The California Energy Plan.

California Senate Bill 1078 calls for the 20 percent RPS to be reached no later than the year 2017. In May 2003, the three energy regulating agencies in California jointly entered into an Energy Action Plan setting the year 2010 as the target year to fulfill the 20 percent RPS (California Consumer Power and Financing Authority et al, 2003).

Appendix Figure 1. Green Power Production Paths:
Base Case vs. the California Energy Action Plan



Appendix Figure 1 compares the projected, minimal green power production path defined in the legislation ("the base case" in this paper) to the more ambitious path contained in the Plan. Under the Plan, the target is met in 2010 and the green power market share remains at 20 percent from 2010 to 2017. In effect, the two production paths meet in the year 2017. The area between the two curves represents additional green power compared to the base case. It will come from accelerated capacity building between 2005 and 2010 that may quality for subsidies. Assuming that green power production is increased in equal annual steps between the year 2004 and 2010 under the Plan, it can be calculated that total green power that qualifies for subsidy increases by 32.6 percent over the base case. It follows from the formulas for the budget constraint above that the average subsidy available in that case is reduced to 66 cents/kWh. This is a reduction that makes it substantially less likely that the RPS will be achieved with the given funds. On the other hand, natural gas prices have remained stubbornly high over the last two years and may very well continue to be high compared to the CEC (2003b) forecast. If so, accelerated green power capacity building may turn out to be an appropriate response to higher prices of electricity in the competitive generation market. This simply reinforces the main point of this paper: That the degree of achievement of California's soft RPS depends essentially on the future path of gas prices.