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**RENEWABLES PORTFOLIO STANDARD:  
DECISION ON PHASE 2  
IMPLEMENTATION ISSUES**

**COMMISSION REPORT**

OCTOBER 2003  
500-03-049F



Gray Davis, Governor

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# Introduction

This report represents the California Energy Commission's (Energy Commission) decisions on Phase 2 issues in the Renewable Portfolio Standard (RPS) proceeding.

The Energy Commission established the RPS proceeding on March 5, 2003 in response to statutory requirements of Senate Bill 1078 (SB 1078, Sher, Statutes of 2002, Chapter 516) and Senate Bill 1038 (SB 1038, Sher, Statutes of 2002, Chapter 515), both signed by Governor Davis on September 12, 2002. These laws took effect January 1, 2003 and are codified in Public Utilities Code (PUC) sections 399.11 through 399.15, and sections 381, 383.5, and 445, respectively.

This report is divided into two sections. The introductory section summarizes the report scope and development process, as well as discusses the legislative requirements of SB 1078 and SB 1038 for each of the Phase 2 issue areas. The report then presents the Energy Commission's decisions, as well as the rationale for those decisions, for each issue area. Appendices include a list of participants in the RPS proceeding, excerpts of relevant statutory language, a glossary of terms, and a list of acronyms used in the report.

## Report Scope

This report presents the Energy Commission's decisions on Phase 2 implementation issues:

- distributing supplemental energy payments (SEPs),
- certifying renewable electricity generation facilities, and
- developing the accounting system for the RPS.

The decisions in this report provide policy direction on a variety of key issues. The Energy Commission recognizes, however, that additional implementation details will need to be identified and resolved during the development of guidelines to certify renewable resources and payment of SEPs.

This report also addresses the relationship between the Renewable Energy Program (REP) established by Senate Bill 90 (SB 90, Sher, Statutes of 1997, Chapter 905) and the RPS as it relates to new renewable facilities. Under SB 90, the Energy Commission provided conditional funding awards to new renewable facilities in the form of production incentives paid on a cents per kilowatt hour basis once facilities begin operation. The Energy Commission pays these production incentives for up to the first five years of project operation.

Of the 71 active new renewable projects that received awards under SB 90, 42 are operating and receiving payments. The remaining 29 projects will receive payments

once they are on-line. Because SB 1038 revises the REP structure and links payments to new renewable electricity generating facilities to the RPS, this report addresses how projects participating in the SB 90 program may also participate in the RPS with respect to SEP eligibility.

The *Renewable Portfolio Standard: Decision on Phase 1 Implementation Issues*, adopted by the Energy Commission on June 11, 2003, also identified issues needing further development during Phase 2. These issues include developing certification procedures in collaboration with other agencies for small hydro, biomass, and municipal solid waste conversion technologies, as well as developing criteria to determine incremental geothermal resources. Although not addressed in this report, these activities are ongoing and will be part of the subsequent guideline development process.

Based on input received from stakeholders, the Energy Commission has deferred consideration of providing preference to projects that provide tangible demonstrable benefits to communities with a plurality of minority or low-income populations. The Energy Commission has also deferred the discussion of caps on SEPs. Parties initially requested, and the Renewables Committee (Committee) agreed, that these topics would be addressed after the California Public Utilities Commission (CPUC) adopted its decision on RPS implementation, Decision 03-06-071, on June 19, 2003.

The Energy Commission recommends deferring these topics and addressing them in the guidebook development process. A deferral will allow parties to evaluate the issues more fully and to consider the CPUC's ongoing efforts to implement the decision. The CPUC Decision 03-06-071 identifies several areas for further work, such as developing standard contract terms and conditions, implementing the least cost best fit evaluation, and establishing the market price referent that the Energy Commission must also consider in implementing the RPS.

This report does not address issues regarding distributed generation or how the RPS will apply to Electric Service Providers (ESPs) or Community Choice Aggregators (CCAs); however, in making its decisions, the Energy Commission made every effort to recognize the eventual and equal participation of these parties. Consistent with the Workplan, the Energy Commission will address these issues during Phase 3 of the RPS proceeding.

Other Phase 3 issues not addressed in this report include developing a final process for accounting and verification and working with the CPUC to address other issues such as resource diversity, competitive sufficiency, and eligibility of distributed generation technologies.

## **Report Development Process**

In SB 1078, the Energy Commission and the CPUC both have clearly defined roles in implementing the RPS and are also directed to work collaboratively across a range of implementation issues. In October 2002, the staff from the two agencies began working together to develop a joint RPS Collaboration Workplan (Workplan).

On March 5, 2003, the Energy Commission issued Order No. 03-0305-04 authorizing the Committee to work with the CPUC to implement the RPS program. The Committee then issued a March 14, 2003 order that initiated a proceeding to address issues identified in the Workplan. The order established administrative procedures for participating in the proceeding and included a copy of the Workplan, along with a proposed schedule of work products and decisions.

The RPS proceeding is divided into three broad phases. Phase 1 issues are those that can be resolved by mid-2003, Phase 2 issues will be addressed by mid- to late 2003, and Phase 3 issues are expected to be resolved by the end of 2003. Phase 1 issues were addressed in the *Renewable Portfolio Standard: Decision on Phase 1 Implementation Issues* (publication number 500-03-023F), which the Energy Commission adopted at its June 11, 2003 Business Meeting.

On May 12 and 13, 2003, the Energy Commission staff held a two-day workshop to solicit input from stakeholders on Phase 2 issues. The workshop topics included distributing supplemental energy payments, certifying renewable electricity generation facilities, and developing an accounting system for the RPS. Participants included trade organizations, electricity generators, environmental groups, consumer protection organizations, utilities, state and county government agencies, and marketers. A complete list of participants is included as Appendix A.

On June 30, 2003, the Committee released a preliminary draft report based on oral and written comments from the May 12 and 13, 2003 workshop, and on the expertise of collaborative staff and technical support contractors. The Committee then held a hearing on July 14, 2003 to get input on the draft report.

The Committee released its final draft report on September 10, 2003 and held a final Committee Hearing on September 29, 2003. The final draft report, along with a set of addenda prepared in response to comments received at the September 29 hearing, was adopted by the Energy Commission at the October 8, 2003 Business Meeting.

The next step in the RPS Proceeding is to begin developing guidelines to implement the decisions in the Phase 1 and Phase 2 reports. PUC section 385.5(h)(1) gives the Energy Commission the authority to develop guidelines to implement the portions of the RPS dealing with funding under SB 1038. These guidelines are exempt from the formal rulemaking requirements of the Administrative Procedures Act. As a result, the Energy Commission can develop guidelines on SEPs and certification of renewable resources within months and can modify them as necessary to adapt to developments in the market.

The Energy Commission intends to develop guidelines governing SEPs and the certification of renewable resources concurrently. Although these guidelines cannot put into practice any procedures contrary to SB 1038 or SB 1078, they may contain revisions to decisions adopted in this report.



Guidelines governing the interim accounting and verification process will be developed in conjunction with amendments to the Energy Commission's regulations for its Power Source Disclosure Program. These regulations are set forth in Title 20 of the California Code of Regulations, commencing with section 1390, and are currently being amended to facilitate overlapping use with the RPS program. On August 6, 2003, the Energy Commission adopted Order 03-0806-03, authorizing the Committee to initiate a rulemaking under Docket 03-RPS-1305 and to amend these regulations. Once the regulations are amended, the Energy Commission will develop guidelines based on the amended regulations to govern the interim accounting and verification process.

The Energy Commission recognizes that the CPUC will continue to develop rules for implementing the RPS, and that both the Energy Commission and the CPUC must be prepared to re-evaluate and modify these rules as necessary in response to new information as well as lessons learned from the program's implementation. To ensure success, the staff will need to continue monitoring the RPS to ensure that the program is meeting the statutory goals in SB 1078, while maintaining flexibility in implementing the program to allow the Energy Commission to make any necessary mid-course corrections.

## **Statutory Requirements**

SB 1078 establishes an RPS program that requires retail sellers of electricity, such as investor-owned utilities (IOUs), to increase the renewable content of their electricity deliveries by at least one percent per year over a baseline level that the CPUC will determine. Retail sellers must meet a target of 20 percent renewable content in their electricity portfolio by December 31, 2017.

Retail sellers may meet the 20 percent renewable content requirement under SB 1078 with both baseline renewable energy and the required additional procurement of renewable energy resources. The quantity of eligible renewable energy resources procured in 2001 determines a baseline of renewable procurement for retail sellers. Above this baseline, retail sellers must procure additional renewable resources.

The CPUC is responsible for setting the baseline and required additional procurement; therefore, any discussion of baseline and required additional procurement in this report is provided only as background and should not be considered as a determination by the Energy Commission.

The Energy Commission's specific responsibilities under SB 1078 include the following: certifying eligible renewable energy resources, designing and implementing an accounting system to verify compliance with the renewables portfolio standard by retail sellers, and allocating and awarding SEPs to cover above-market costs of renewable energy.

SB 1038 gives the Energy Commission continuing authority to implement the REP, but also makes changes to the REP's structure and funding allocation. One of the structural

changes is linking payments to new renewable electricity generation facilities to the RPS.

Statutory requirements for the Phase 2 activities — distributing supplemental energy payments, certifying electricity generation facilities, and developing an RPS accounting system — are summarized below. Pertinent sections of the statutory language are provided in Appendix B. In addition, Appendix B includes the statutory language added by Senate Bill 183 (SB 183, Sher, Statutes of 2003, Chapter 666) and Senate Bill 67 (SB 67, Bowen, Statutes of 2003, Chapter 731), which the Governor approved on October 2, 2003 and October 8, 2003, respectively. SB 183 recasts the provisions of Public Utilities Code sections 383.5 and 445 into Public Resources Code sections 25740 through 25751, and SB 67 establishes new RPS eligibility requirements for out-of-state renewable power. The Energy Commission will consider the statutory changes imposed by SB 183 and SB 67 in developing guidelines under the Phase 1 and Phase 2 RPS decisions.

## **1. Distributing Supplemental Energy Payments**

SB 1078 directs the Energy Commission to “allocate and award supplemental energy payments” to “eligible renewable energy resources to cover above-market costs of renewable energy.” The CPUC, in consultation with the Energy Commission, will determine what constitutes these above-market costs.

SB 1038 describes how public goods charge (PGC) funding is allocated in the Energy Commission’s Renewable Energy Program. SB 1038 allocates 51.5 percent of the \$135 million in PGC funds collected annually to the New Renewable Resources Account to fund the New Renewable Facilities Program (NRFP). The Energy Commission recently reallocated an additional 4.5 percent of the funds from the Customer Credit Account to the New Renewable Resources Account for funding the NRFP.

The NRFP will award SEPs to cover appropriate above-market costs of renewable resources that retail sellers select to fulfill their RPS obligations to “foster the development of new in-state renewable electricity generation technology facilities, and to secure for the state the environmental, economic, and reliability benefits that continued operation of those facilities will provide.”

SB 1038 specifies that repowered existing facilities are also eligible for SEPs “if the capital investment to repower the existing facility equals at least 80 percent of the value of the repowered facility.”

SB 1038 contains specific directions for awarding SEPs. The Energy Commission:

- shall make payments for 10 years or the length of the contract with the electrical corporation if it is of a lesser duration,

- shall reduce or terminate SEPs for projects that either fail to commence or maintain operations in accordance with contractual obligations or that fail to meet eligibility requirements,
- shall manage the funds in an equitable manner so that retail sellers may meet their RPS obligations,
- may establish payment caps,
- may require an applicant competing for funding to post a forfeitable bid bond or other financial guaranty of the applicant's good faith intent to move forward with the project expeditiously, and
- may provide preference to projects that provide tangible, demonstrable benefits to communities with a plurality of minority or low income populations.

SB 1038 further states that facilities may NOT receive SEPs if the electricity produced is:

- sold under an existing long-term contract with an existing in-state electrical corporation if the contract includes fixed energy or capacity payments,
- used on-site or sold in a manner that is excluded from competitive transition charge payments, or
- produced by a facility owned by an electrical corporation or publicly-owned utility.

SB 1078 and SB 1038 also describe what renewable energy resources qualify for the RPS, and for SEP. The Energy Commission's decisions on implementing these provisions are discussed in the *Renewable Portfolio Standard: Renewables Committee Decision on Phase 1 Implementation Issues*, May 2003, which was formally adopted on June 11, 2003.

SB 1078 defines an "eligible renewable energy resource" as a facility that meets the definition of "in-state renewable electricity generation technology" as provided in SB 1038. Such a facility must meet the following criteria:

- use biomass, solar thermal, photovoltaic, wind, geothermal, fuel cells using renewable fuels, small hydroelectric generation of 30 megawatts or less, digester gas, municipal solid waste conversion using a non-combustion thermal process, landfill gas, ocean wave, ocean thermal, tidal current, and any additions or enhancements to the facility using that technology, and
- be located in California or near the border with the first point of connection to the Western Electricity Coordinating Council transmission system located within California. SB 1038 states that the Energy Commission may find a facility located out-of-state eligible for SEPs if it meets specific requirements.

SB 1038 and SB 1078 also impose additional restrictions on the eligibility for SEPs of small hydro, biomass, solid waste conversion, municipal solid waste (MSW) combustion facilities, and geothermal. New small hydro, biomass, and MSW facilities are eligible for SEPs if they meet specific criteria. New small hydro facilities qualify for SEPs if they do not require new or increased appropriation or diversion of water. New biomass facilities qualify for SEPs if they certify to the Energy Commission that they use certain fuel types obtained in an approved manner. MSW facilities must use a non-combustion conversion process that meets an explicit list of operating criteria to qualify for SEPs.

Incremental geothermal production may meet the criteria for “new” in-state renewable electricity generation technology facilities described in SB 1038 and, therefore, be eligible for SEPs. The criteria for evaluating such eligibility have not yet been determined. The Energy Commission’s adopted decision on Phase 1 issues states that a post-2001 repower of an existing geothermal resource must be found to be incremental as well as “new” to be eligible for SEPs.

## **2. Certifying Electricity Generation Facilities**

SB 1078 directs the Energy Commission to “certify eligible renewable energy resources” that it determines meet the criteria of an “eligible renewable energy resource” qualifying towards meeting the state’s 20 percent renewables target.

SB 1038 directs the Energy Commission to “register” facilities that are eligible for funding from the Existing Renewable Facilities Program and the NRFP. SEPs will be awarded and distributed through the NRFP. Facilities eligible to receive funding from these programs “...shall be registered in accordance with criteria developed by the Energy Commission....”

## **3. Developing an RPS Accounting System**

SB 1078 directs the Energy Commission to “design and implement an accounting system” to serve three purposes:

“ . . . to verify compliance with the renewables portfolio standard by retail sellers, to ensure that renewable energy output is counted only once for the purpose of meeting the renewable portfolio standard of this state or any other state, and for verifying retail product claims in this state or any other state.”

SB 1078 further states that “in establishing the guidelines governing this system, the Energy Commission shall collect data from electricity market participants that it deems necessary to verify compliance of retail sellers.” When seeking accounting system data from the electrical corporations, SB 1078 directs the Energy Commission to request data from the CPUC. The CPUC must collect that data from the electrical corporations and provide it to the Energy Commission within 90 days of the request.

# ENERGY COMMISSION DECISIONS

This section provides the Energy Commission's decisions and rationale regarding distributing supplemental energy payments, certifying electricity generation facilities, and developing the accounting system for the RPS.

## Distributing Supplemental Energy Payments

As required in SB 1078, the Energy Commission must "allocate and award supplemental energy payments ... to eligible renewable energy resources to cover above-market costs of renewable energy." To do so, the Energy Commission must resolve a number of eligibility, allocation, and administrative issues.

Eligibility issues include the following:

- definition of "new" and "repowered,"
- eligibility of bilateral contracts,
- potential for multiple awards,
- what entities may receive SEPs, and
- SEP interaction with SB 90 funding.

Allocation and administrative issues are as follows:

- SEP payment terms,
- the need for financial and performance guarantees as well as SEP termination,
- the availability of PGC funds, and
- the need for flexibility in developing and modifying program guidelines.

The Energy Commission's decisions and rationale on these issues are as follows.

### Definition of "New"

**Decision:** Resources that first begin commercial operation or are repowered on or after January 1, 2002 and meet the other eligibility requirements of SB 1038 be considered "new" and thus eligible for SEPs. The on-line date used to designate a facility as "new" will be periodically updated in the guidebooks as needed.

**Discussion and Rationale:** SB 1038 establishes the New Renewable Resources Account, but does not establish a date or method to determine when a renewable energy resource is considered "new." SB 1078 directs the Energy Commission to "provide supplemental energy payments from funds in the New Renewable Resources Account" to eligible renewable energy resources to cover appropriate above-market costs of those resources, but like SB 1038 does not define "new."

SB 1078 does, however, direct the CPUC to establish a baseline renewable procurement level “based on the actual percentage of retail sales procured from eligible renewable energy resources in 2001.” The Energy Commission’s decision, therefore, is consistent with the law, because any renewable energy resource commercially operating before January 1, 2002 could have been included in the baseline of an electrical corporation or other obligated entity.

The Energy Commission’s decision is also generally consistent with comments by Chateau Energy Inc. (CEI). Other parties, however, presented different recommendations. Calpine Corporation proposed that, for the purpose of SEP eligibility, “new” facilities are those that began operation after September 26, 1996. In addition, Calpine Corporation recommended that the designation as “new” remain in place for ten years after a facility’s commercial operation date.

The Energy Commission disagrees that facilities built between 1996 and 2002 should be eligible for SEPs. Such facilities were completed under the market conditions at the time and are operating under contract or market payments for their energy without expectation of or recourse to SEPs. Also, the most recent SB 90 New Renewable Resources Account auction, held in June 2001, defined “new” as coming on-line after October 12, 2000, and it would not make sense to now define “new” as before this date.

Renewable Energy Inc. (REI) suggested that facilities that begin operation on or after the date the legislation passed, September 12, 2002, be considered “new.” The Energy Commission prefers not to use this date because a facility that came on-line between January 1, 2002 and September 12, 2002 might not be part of any retail seller’s initial baseline amount of resources, but would also not qualify for SEPs.

The California Wind Energy Association (CalWEA), The Utility Reform Network (TURN), and Vulcan Power Company suggest that new facilities eligible for SEPs should be those facilities that come on-line after the date of a retail seller’s solicitation for renewable energy to meet its RPS obligation. Although a similar approach was used in implementing SB 90, the Energy Commission prefers to set an initial fixed date for defining “new” for the RPS.

The rolling dates used in SB 90 were relatively clear because the Energy Commission’s auctions were statewide solicitations separated by substantial time. Under the RPS, there may be multiple solicitations within the same year held by different parties with different eligibility rules or requirements, which could lead to a variety of dates by which resources could be defined as “new.” A set date to qualify as “new” and eligible for SEP payments will be more straightforward and easier for the Energy Commission to implement.

The Independent Energy Producers (IEP) also advocated having the “new” designation set to a fixed date. IEP proposed that the designation of “new” or “existing” should depend on funding eligibility. According to IEP, a facility should be able to qualify as “new” and eligible for SEPs for ten years and then qualify for payments from the Existing Renewable Facilities Program. The Energy Commission disagrees with IEP, because the Existing Renewable Facilities Program was established for a specific set of

resources more limited than those resources eligible for SEPs. The Energy Commission also believes that the Legislature never envisioned automatic eligibility for Existing Renewable Facilities Program payments after a facility has captured all of its New Account or SEP payments.

At some point it may be desirable to update the definition of “new” to help foster construction of new facilities, to adapt to changes in the market, or to keep the program from becoming stale. Therefore, the Energy Commission will use the guidebooks to make any needed revisions to the required commercial operation dates for new renewable facilities.

Designating a facility as “new” based on its on-line date, as described above, does not necessarily imply eligibility for SEPs. A facility that is not an eligible renewable resource, or does not satisfy eligibility criteria established by the RPS, is not eligible for SEPs even though it may be designated “new.”

## **“Repowered” Definition**

Decision: Repowered generators will be eligible for SEPs if they replace their prime generating equipment and use tax records, or an acceptable alternative, to demonstrate that they have made capital investments in the facility equal to “at least 80 percent of the value of the repowered facility,” as required by SB 1038. For generators with existing long-term contracts originally entered into before September 26, 1996, only generation that is above and beyond what is already under contract, as determined in accordance with Public Utilities Code section 399.6 (c)(1)(C), may compete to satisfy the RPS obligation of an electrical corporation and be eligible for SEPs.

Discussion and Rationale: SB 1038 contains two provisions that affect the eligibility of repowered projects for SEPs. PUC section 383.5(d)(3) states that “Repowered existing facilities shall be eligible for funding under this subdivision if the capital investment to repower the existing facility equals at least 80 percent of the value of the repowered facility.” The second provision imposes additional eligibility limits on generators with certain existing long-term contracts. For these generators, PUC section 383.5(d)(2)(C)(i) specifies that the Energy Commission may not award SEPs for renewable electricity produced and “sold under an existing long-term contract with an existing in-state electrical corporation if the contract includes fixed energy or capacity payments, except for that electricity that satisfies the provisions of [PUC section 399.6(c)(1)(C)].”

PUC Section 399.6 (c)(1)(C) provides that if a facility produces additional electricity because of a repower or a separable enhancement, the additional electricity is only eligible for funding from the NRFP if it does not also receive capacity payments as part of a utility contract. The exception to this restriction is a facility whose capacity has expanded by a significant amount within the constraints of the contract that produces additional generation also above a calculated historical amount for the facility.

To establish what facilities are eligible for SEPs, the Energy Commission must (1) define what constitutes a “repowered” facility, and (2) determine how facilities will

demonstrate that the capital investment made “equals at least 80 percent of the value of the repowered facility.”

### **Definition of Repowered**

The Energy Commission believes that the reason the Legislature made repowered facilities eligible was to enhance the efficiency of existing facilities where appropriate. Enhanced efficiency can improve electrical output, fuel efficiency, and environmental characteristics, and can be achieved by replacing a facility’s existing prime generating equipment with new prime generating equipment.

Therefore, for a facility to be considered “repowered,” its prime generating equipment must be replaced with new prime generating equipment, that is, equipment that has not been used before. “Prime generating equipment” for each of the resource categories is defined as follows:

- Wind: the entire wind turbine, including the generator, gearbox (if any), nacelle, and blades.
- Biomass: the entire boiler. Stoker boilers may be replaced with boilers using improved stoker technology or fluidized bed technology.
- Geothermal: the entire steam generator, including the turbine rotors, shaft, stationary blades, and any gear assemblies.
- Small hydro: the entire turbine and structures supporting the turbine.
- Solid waste conversion: the entire gasifier (gasifying equipment) and combustion turbine.
- Landfill gas: the entire internal combustion engine or combustion turbine as applicable.
- Digester gas: the entire digester unit and internal combustion engine or combustion turbine as applicable.
- Solar thermal: the entire steam turbine.

All prime generating equipment at the facility must be replaced with new equipment for the facility to qualify as a repowered facility. For example, a 25 MW wind facility consisting of 50 separate wind turbines must at a minimum replace each of the 50 wind turbines with new turbines of like or greater capacity for the entire 50 MW facility to qualify as a repowered facility. The Energy Commission recognizes that a wind facility owner may want or need to repower only a portion of the turbines owned at a site, and does not exclude that option.

However, it is not necessary for a facility to replace its existing electrical generators or fuel processing and delivery equipment, since the replacement of this equipment will



produce little or no improvement to the facility's efficiency and, therefore, do not warrant the additional expense. Exceptions are cases in which the electrical generator is an integral part of the prime generating equipment, such as for wind facilities, or where the fuel processing and delivery equipment is an integral part of the prime generating equipment via the fuel conversion process, such as for solid waste conversion facilities and digester gas facilities.

Several parties supported using new equipment to enhance efficiency at a repowered facility. Calpine proposed using new or refurbished equipment, as long as that equipment substantially enhances a facility's performance through increased output, greater fuel efficiency, or improved environmental characteristics.

Although the Energy Commission recognizes that refurbished equipment can improve a facility's performance, at least relative to its pre-refurbishment performance, refurbished equipment may not always result in enhanced efficiency. In some cases, refurbishing may simply restore equipment to its original level of performance, without actually enhancing or improving efficiency. Moreover, allowing a facility to refurbish its prime generating equipment rather than replace it with new equipment would be difficult to monitor, and could lead to facility operators attempting to circumvent the rules by claiming that annual maintenance work resulted in the equipment's refurbishment. The risk of this would be greatest when the value of the existing equipment has already been depreciated to zero, since in these cases the 80 percent threshold would effectively be determined by comparing the expense of the refurbishment with itself.

### **Meeting the 80 Percent Criterion**

The Energy Commission believes that the Legislature imposed the 80 percent threshold to assure that only those facilities that are primarily "new" are eligible for SEPs. However, the statute provides little guidance regarding how the Energy Commission is to determine whether the capital investment made to repower a project equals "at least 80 percent of the value of the repowered facility."

To make this determination, the Energy Commission must decide the following:

- what capital investments will be counted towards the 80 percent threshold,
- how the value of the capital investments will be established,
- the meaning of the term "repowered facility," and
- how the "value of the repowered facility" will be determined.

In their written comments, CalWEA, CEI, and Vulcan Power Company suggested that the Energy Commission should use provisions of the federal tax code to determine eligibility for repowered facilities. The Energy Commission agrees that it is desirable to use the federal tax code to the extent possible, because it provides guidance on differentiating "capital investments" from other types of expenses such as operation and maintenance expenses. In addition, tax records can be used to establish a readily available proxy for "value" which, because it is used for another purpose, is less likely to be "gamed" to establish SEP eligibility.

The Energy Commission believes that it can use tax records to develop detailed guidelines for generators to use to demonstrate compliance with the 80 percent threshold. One possible approach is outlined below:

1. The “capital investments” counted toward the 80 percent threshold would be the capital investments on that portion of the facility that contributes directly to the production of electricity, including:
  - the new prime generating equipment
  - electrical generators
  - fuel processing and delivery equipment
  - any associated process control equipment and structures used for structural support of the prime generating equipment, electrical generators, fuel processing and delivery equipment, and associated process control equipment.

The facility’s environmental control equipment, such air pollution control equipment, would not be considered because such equipment does not contribute directly to the production of electricity.

2. The “value” of the capital investments would be determined using the original tax “basis” declared to the Internal Revenue Service to calculate depreciation. The tax basis is generally what a business pays for an item to be depreciated.
3. The “repowered facility” would be defined as all of the new and/or existing prime generating equipment, electrical generators, fuel processing and delivery equipment, and any associated process control equipment and structures at the facility. To determine whether the 80 percent threshold is met, the value of capital investments would be compared to the “value” of the repowered facility. The land on which the facility sits would not be considered part of the repowered facility for purposes of determining the 80 percent threshold. Similarly, intangibles such as the value of a facility’s power purchase agreement or its goodwill would not be considered part of the repowered facility.
4. The “value” of the repowered facility would be the sum of the tax basis declared for all of the equipment and structures in the repowered facility as of the year the facility is repowered. For new equipment and structures, the value of the repowered facility would be the original tax basis; for existing equipment and structures, the value of the repowered facility would be the tax basis as adjusted for depreciation. For facilities financed using a sale/lease-back or similar structure, the original tax basis of the equipment and structures for both the lessor and lessee would be considered.

Several parties — including CEI, Calpine, and Ridgewood Renewable Power — raised issues concerning the availability of tax records for existing equipment. These tax records may not be readily available or in the possession of the facility’s current owner or operator. Such would be the case if the equipment was originally purchased and placed in service by a prior owner or operator, or if the equipment was purchased by a third party under a sale/lease back arrangement. While it may be difficult to secure the needed tax records, these records provide the best proxy for determining a facility’s

value, these records can and should be produced, and the burden of securing the records should fall on the party seeking designation as a repower.

CalWEA and CEI each proposed alternatives to this adjusted tax basis approach. CalWEA recommended that the 80 percent threshold be determined using the fair market value (FMV) of the refurbished facility. CEI recommended that the threshold be determined using an engineering cost analysis (ECA). Both of these alternatives offer benefits over the adjusted tax basis approach and would avoid the need for tax records and the problems associated with records' availability. However, both the FMV and ECA alternatives can be manipulated by using subjective criteria to produce artificially high or low results. In addition, neither the FMV nor ECA approach offers the type of assurances associated with the filing of tax returns, and may, as a result, be viewed as less reliable. Therefore, the Energy Commission rejects the use of either the FMV or ECA approach in favor of the adjusted tax basis approach.

However, recognizing that the availability of tax records may hamper the repower determination, the Energy Commission will allow an alternative approach: determining value based on a facility's "replacement" value, rather than its adjusted tax basis. Under this alternative approach, the facility's value is based on the fixed capital cost of replacing the prime generating equipment, electrical generators, fuel processing and delivery equipment, and any associated process control equipment and structures. The replacement cost of new equipment would be based on the equipment's purchase price and would result in the same value when compared to the adjusted tax basis approach. The replacement cost of existing, unreplaced equipment ("retained equipment") would be based on an independent estimate of the capital costs that would have to be incurred to replace the retained equipment. A facility would be considered "repowered" if the replacement cost of the new equipment is equal to or greater than 80 percent of the sum of the replacement cost of the new equipment and the independent estimate of the replacement cost of the retained equipment.

It is likely that companies using the replacement cost approach will find that more of a facility will have to be replaced for the facility to be considered "repowered" because the independent estimate of the cost of replacing the retained equipment will almost always be higher than the adjusted tax basis of the equipment, particularly when the retained equipment has been depreciated to a zero basis for tax purposes. Although using this alternative approach may make it more difficult for a facility to meet the 80 percent repowering threshold, it is a reasonable alternative for parties who are unable or unwilling to secure the necessary tax records to utilize the adjusted tax basis approach.

Some companies may also find the replacement cost approach simpler to use. For example, companies that plan to almost completely renovate their facilities will likely get estimates for complete replacement of all equipment. Such companies could readily establish eligibility by providing such estimates and indicating which costs they are "backing out" because the equipment will actually be retained. The revamped facility would be considered "repowered" as long as the capital cost of the equipment to be retained is no more than 20 percent of the capital cost of all of the equipment.

This alternative “replacement” approach is modeled in part after new rules adopted by the U.S. Environmental Protection Agency for the New Source Review (NSR) permit program, and encourages parties to review these new rules in commenting on the alternative “replacement” approach. Under the new NSR rules issued on August 27, 2003, the replacement of certain process equipment is automatically exempt from the NSR permit review process if the following four conditions are met:

1. the equipment is replaced with the identical or functional equivalent component
2. the replacement does not change the basic design parameters of the process unit
3. the replacement does not cause the unit to exceed any emission limits
4. the fixed capital cost of the replaced equipment plus the cost of any related replacement activity (labor, contract services, etc.) does not exceed 20 percent of the replacement value of the entire process unit.

For the Energy Commission’s purposes, the fourth condition is the most pertinent because, similar to the repowering requirements, it hinges on a threshold determination of value: 20 percent of the process unit’s replacement value for NSR and 80 percent of a repowered facility’s value for RPS/SEPs. The new NSR rules give a facility operator several options for determining the replacement value of the new process unit. Because none of these options are based on a facility’s adjusted tax basis, they avoid the issue of tax record availability.

The Energy Commission may consider the use of the FMV or ECA approach, as well as other approaches, if during the guideline development process it determines that the problems associated with the adjusted tax basis approach or the alternative “replacement” approach are too difficult to overcome.

When generators apply to the Energy Commission for eligibility certification for the RPS and SEPs, they will not know the actual cost of the new prime generating equipment that they intend to install. Thus, it will be necessary for the Energy Commission to certify these generators based on estimates that will be checked against tax returns or independent appraisals filed after the repowered facility goes into operation. When the Energy Commission develops detailed guidelines, it may be desirable to establish guidelines for generators wishing to repower only a portion of an existing facility or to repower a facility in stages.

For generators with existing contracts that wish to repower, SB 1038 imposes further restrictions. As noted above, the Energy Commission may not award SEP payments for renewable electricity produced and “sold under an existing long-term contract with an existing in-state electrical corporation if the contract includes fixed energy or capacity payments, except for that electricity that satisfies the provisions of [Public Utilities Code section 399.6(c)(1)(C)].”

The provisions of section 399.6 (c)(1)(C) assure that for facilities with an existing long-term contract entered into before September 26, 1996, production incentives are

available only for additional generation over and above that which was originally contracted for. The provisions of this section also specify the procedures to determine what qualifies as additional generation. If a repowered facility has an existing long-term contract governed by section 399.6(c)(1)(C), only the quantity of the electricity generated considered additional generation under section 399.6 (c)(1)(C) may compete to satisfy the RPS obligation of an electrical corporation and be eligible for SEPs. If an existing long-term contract expires, then the renewable generator would be eligible for funding as a “repowered” facility on the same terms as other generators.

## **Eligibility of Bilateral Contracts**

**Decision:** Bilateral contracts between electrical corporations and renewable energy resources outside of a competitive solicitation are not eligible for SEPs.

**Discussion and Rationale:** Allowing SEP awards for contracts established between electrical corporations and renewable energy resources outside an RPS solicitation is inconsistent with the RPS structure that ties SEPs to market price referents determined in specific solicitation cycles. In addition, allowing bilateral contracts to be eligible for SEPs could also undermine the RPS by circumventing the least-cost-best-fit analysis required under SB 1078 and is inconsistent with the goal of using a robust competitive process to allocate public funds.

Under the RPS, SEP amounts are tied explicitly to costs above an applicable market-price referent that is part of a utility solicitation process. The CPUC is prohibited from informing bidders in a solicitation about the applicable market price referent until the solicitation is held. Similarly, the CPUC is prohibited from receiving the results of a solicitation until after determining the applicable market price referents. Because a market price referent cannot be clearly applied outside of a utility solicitation, SEPs cannot result from bilateral contracts.

CalWEA submitted comments supporting this position, but noted that projects with SB 90 awards could reasonably be allowed to keep their awards and enter into a bilateral contract. The Energy Commission agrees that projects with SB 90 awards do not result in the SEP issues raised above and, therefore, should not be required to relinquish those awards if they enter into a bilateral contract with a retail seller. However, should a project with an SB 90 award choose to participate in an RPS solicitation and be eligible for SEPs, the Energy Commission would require the project to relinquish that award. This limitation is discussed in more detail in a later section of this report

## **Entities That May Receive SEPs**

**Decision:** The Energy Commission will pay SEPs to the entity with which an electrical corporation or other obligated entity holds a contract for renewable energy resources under the provisions of the RPS.

Discussion and Rationale: SB 1078 states that “supplemental energy payments shall be awarded only to facilities that are eligible for funding under this subdivision.” This does not mean that only individual renewable energy generators may contract with obligated entities and be eligible for SEPs. It is possible that electrical corporations or other obligated entities will contract with entities other than the renewable energy generators to satisfy their obligation.

Wholesale power marketers and other financial intermediaries may acquire the rights to the energy and renewable energy attributes or certificates from a renewable energy resource for its generation along with the rights to sell those products. The Energy Commission, therefore, will award SEPs to the entity that holds the contract with an electrical corporation or other obligated entity that satisfied their RPS obligation, provided that the contracting entity can identify and establish its rights to sell renewable energy from a certified renewable energy resource. Further, any renewable facility that sells its generation to a contracting entity will be obligated to document the facility’s eligibility and generation.

Comments from Calpine, CalWEA, CEI, Vulcan, and Renewable Energy Inc. supported this recommendation, as did general discussion among parties at the staff workshops.

## **SEP Interaction with SB 90 Funds**

Decision: A project holding a conditional funding award from the Energy Commission’s NRRRA under SB 90 may participate in an IOU solicitation under the new RPS structure in hopes of securing a PPA, but cannot receive SEPs in addition to the SB 90 award.

To participate in a specific IOU solicitation, bidders with SB 90 awards whose projects are not yet on-line must state their intention to either (1) keep the SB 90 award and agree to be ineligible for SEPs or (2) relinquish the SB 90 award and compete for potential SEPs. Similarly, on-line projects that have already received payments from the New Renewable Resources Account under SB 90 cannot receive SEPs unless they state their intention to relinquish their SB 90 award when they submit their SEP bid. Further, any funding awarded through SEPs will be reduced by the amount of any payments already made to these projects under SB 90.

A winning bidder that chooses to keep its SB 90 award can receive payments under that award’s terms and conditions, but is ineligible for SEPs resulting from that solicitation. A winning bidder that chooses to be eligible for SEPs must relinquish its SB 90 award, or any payments already made under that award, once it executes a contract with a utility, regardless of whether or not the bidder ultimately qualifies for SEPs. However, if a bidder does not secure a contract under the RPS solicitation, the bidder will not be required to relinquish its SB 90 award.

Projects may also retain their SB 90 awards if they enter into a bilateral contract with an IOU outside of a solicitation, should the CPUC allow such procurement. Projects that enter into contracts or agreements with other retail sellers will face similar rules

governing interaction with SEP payments. These rules will be established once the CPUC specifies the process by which other retail sellers are obligated under the RPS.

Discussion and Rationale: Under the SB 90 program that began in 1998, developers of prospective new renewable energy facilities competed for a fixed amount of PGC funding in the form of production incentives of up to 1.5 cents per kilowatt-hour (kWh) for the first five years of generation. Developers were not required to have a power purchase agreement (PPA) to be able to bid for funding.

The Energy Commission held three separate auctions — the first in June 1998, the second in October 2000, and the third in June 2001. The October 2000 and June 2001 auctions were structured to encourage rapid development of winning projects to provide additional generation during California's energy crisis in 2000-2001.

The auctions were successful in awarding funds to a diverse group of the most efficient prospective renewable energy generators. Seventy-one renewable projects, totaling 1,266 megawatts (MW) of capacity, hold active funding awards resulting from the auctions. However, because of changes in California's wholesale power market, only about 25 percent of the capacity originally awarded funding has completed development and construction and is commercially operating.

Currently, 42 projects totaling 329 MW are on-line and receiving incentive payments. Developers of 29 projects representing more than 900 MW of capacity still have conditional funding awards that they could use if they are able to complete development and construction and begin commercial operation. Of these 29 projects, the Energy Commission staff expects nine totaling 237 MW to come on-line in 2003. The remaining projects are scheduled to come on-line in 2004 and 2005.

The October 2000 and June 2001 auctions imposed significant reductions of bidders' expected PGC awards for projects coming on-line after certain dates specified in each auction. Of the 29 projects not yet on-line, 15 projects currently have awards that have been reduced by 50 percent; depending on when the projects come on-line, the awards could be further reduced or even cancelled.

One of the major barriers auction winners have faced while trying to bring their projects on-line has been the difficulty in securing PPAs. The Energy Commission, therefore, does not want to establish rules that will preclude a project holding an SB 90 award from securing a contract with a utility as a result of an RPS solicitation. However, it could potentially dismantle the results of the selection process to allow projects to choose between keeping their SB 90 awards or receiving SEPs after the results of the procurement solicitation are determined.

By allowing projects with SB 90 awards to participate in RPS solicitations with the understanding that they must relinquish their SB 90 awards to be able to receive SEPs, the Energy Commission maintains its support of new facilities with conditional SB 90 funding while preventing those projects from "double dipping" PGC funds or taking unfair advantage of the procurement process.

The comments from CalWEA, TURN, PG&E, SDG&E, and Vulcan Power are generally consistent with the Energy Commission's decision, although CEI stated, "Relinquishment of the SB 90 award should occur as part of the agreement for SEPs between the Energy Commission and the bidder, and not before."

Calpine Corporation proposed that SB 90 awardees should be eligible for SEPs if they give up their award. However, in addition to choosing between the SB 90 award and SEPs, Calpine also suggested that a bidder should be given the option of withdrawing its bid after the market price referent has been revealed. The Energy Commission believes that this option invites gaming and would disrupt the results of the least-cost-best-fit analysis required under SB 1078.

## **SEP Payment Terms**

**Decision:** The Energy Commission will pay SEPs only for actual generation by an eligible renewable energy resource. Generation that has been curtailed or has otherwise not occurred is not eligible for SEPs, even if a facility's contract specifies curtailment payments or provision of replacement energy.

The Energy Commission will pay SEPs for ten years, or the length of the RPS contract, whichever is less. Facilities with eligible contracts for a term longer than ten years are still eligible to receive SEPs, but only for a maximum of ten years. In accordance with SB 1038, the CPUC can authorize contracts with terms of less than ten years; facilities with these qualifying contracts will receive SEPs for the length of the contract term. The Energy Commission believes, however, that SEPs were intended to foster long-term contracts; consequently, no SEPs will be made for contracts with terms of less than three years.

Finally, the Energy Commission will pay SEPs monthly and require third party verification of the energy produced, at least until the long term tracking system is in place. Further operational details will be determined when the guidelines for the NRFP are developed. The Energy Commission defers any decisions about SEP payment terms for ESPs and CCAs until Phase 3.

**Discussion and Rationale:** SB 1078 states that the Legislature requires "all electrical corporations to procure a minimum quantity of output from eligible renewable energy resources as a specified percentage of total kilowatt-hours sold to their retail end-use customers each calendar year." This statement establishes the Legislature's intent to establish an RPS based on generation output from renewable energy resources, measured in kilowatt-hours, rather than on capacity. To pay SEPs on any basis other than energy generated would be at odds with this intent.

Payments from the Renewable Energy Program through the SB 90 program are made monthly after the Energy Commission receives third party verification of the generation. Calpine, CalWEA, CEI, and Vulcan suggested that SEP payments should be made on the same schedule as PPA payments. Many parties proposed that payment on a monthly basis would be appropriate as well as consistent with the potential PPAs.



## Potential for Multiple Awards

**Decision:** One facility may apportion its electricity generation into two or more separate contracts, with energy from each of these contracts qualifying for SEPs, provided that all of the generation under each contract is reported to the Energy Commission accounting system for tracking purposes. However, facilities are only eligible for SEPs for the first ten years of generation from their initial RPS contract(s).

Generation that an IOU contracts for that is awarded SEPs may not compete for a second award with an IOU after that contract expires, even if SEPs were awarded for less than 10 years. An appeal process will be established for situations in which a contract is terminated for some reason beyond the generator's control, so the generator may petition to be eligible to compete for another SEP award. In no case shall the cumulative number of years of SEP payments exceed 10 years. These provisions also apply to the portion of the facility output or capacity under contract if only a fraction of the facility was under an RPS contract.

**Discussion and Rationale:** The energy produced from a renewable energy resource associated with a contract with electrical corporations may only be eligible for SEPs once. SB 1038 specifies that SEPs "shall be paid for the lesser of ten years, or the duration of the contract with the electrical corporation." The Energy Commission does not want to provide SEPs for multiple short-term contracts with electrical corporations, because it could create incentives for short-term contracts that are counter to the intent of SB 1038.

Although a generator may find it desirable to sell its entire output to one retail seller, the generator should not be prevented from packaging its generation to more than one retail seller. This option will provide flexibility to both the utilities and the generators as they pursue PPAs.

There may be cases where one renewable energy resource sells portions of its output to more than one retail seller through separate contracts. In such a case, one facility could qualify for more than one SEP award, with each SEP award tied to the amount of energy contracted for by each retail seller. The generator would be required to report the entire amount of energy generated from the facility to the Energy Commission.

One unit of energy, or percent of production, cannot receive more than one SEP award. For example, the renewable energy resource may have a contract to sell 30 percent of its output to one retail seller, under terms that qualify it for an SEP award. This portion of the generation would not qualify for a second award. The generator would report its monthly generation to the Energy Commission and also report the deliveries under contract to the retail seller. The remaining 70 percent of the output from the generator could also be eligible for SEPs if the generator successfully won a contract and an SEP award for that portion of its generation.

To foster project development, the Energy Commission is interested in encouraging the execution of long-term contracts between the IOUs and the generators. By disallowing multiple SEP awards, the Energy Commission intends to encourage entities to execute contracts that are long enough to support renewable project development. The Energy Commission does not want to inadvertently penalize generators whose RPS contracts may be terminated for reasons beyond the generators' control prior to having received their entire SEP award. In such an event, the generator may petition the Energy Commission for permission to compete for a subsequent SEP award. In no case, however, may the total number of years of SEP payments exceed 10 years.

The Energy Commission defers to a later date the rules related to RPS compliance for ESPs and CCAs.

## **Financial and Performance Guarantees and SEP Termination**

**Decision:** PPAs with the electrical corporations should address financial and performance issues related to renewable energy resources that are awarded SEPs. The Energy Commission will terminate SEPs if the PPA that is the basis of the SEP award is terminated. The Energy Commission does not contemplate holding an auction for SEPs for solicitations by electrical corporations at this time. Auctions for the distribution of SEPs to other retail sellers may be appropriate, and the Energy Commission will make such a determination during Phase 3.

**Discussion and Rationale:** SB 1038 provides the Energy Commission with the authority to "require applicants competing for funding to post a forfeitable bid bond or other financial guaranty as an assurance of the applicant's intent to move forward expeditiously with the project proposed." Further, SB 1038 directs the Energy Commission to reduce or terminate SEPs "for projects that fail either to commence and maintain operations consistent with the contractual obligations to an electrical corporation, or that fail to meet eligibility requirements."

The CPUC, however, is in the process of establishing RPS compliance rules for electrical corporations as a part of the electrical corporations' overall procurement planning proceeding. The Energy Commission expects that the electrical corporations will satisfy their obligations to procure renewable energy resources through their own procurement methods, and does not see a role for Energy Commission hosted auctions for SEP funding.

Because the Energy Commission does not currently contemplate hosting auctions for SEP funding at this time, it does not recommend establishing financial or performance standards above those required of the facilities under their PPAs with the electrical corporations. If the PPA that is the basis of the SEP award is terminated for non-performance or any other reason, the Energy Commission will terminate the SEP award at the same time. SEP awardees whose utility contracts have been terminated for reasons beyond the awardee's control may petition the Energy Commission for permission to compete for a subsequent SEP award as described earlier in the "Potential for Multiple Awards" section of this report.

## Availability of Public Goods Charge Funds

Decision: The Energy Commission recommends that the CPUC should transmit market price referent information to the Energy Commission at the same time that information is revealed to the utilities. The Energy Commission further recommends that the CPUC direct the utilities to transmit information on utility-selected projects to the Energy Commission at the same time this information is transmitted to the CPUC.

The Energy Commission will compare the requested SEPs with the availability of PGC funds to determine if PGC funds are adequate to cover SEPs for all the selected winning bidders in the utilities' solicitation. If PGC funds are inadequate, then the Energy Commission will identify which bidders could be fully funded under the utilities' least-cost-best-fit ranking required under SB 1078, so that projects with the best ranking would be awarded SEPs first. If funding is available to cover only a portion of the SEPs for which a bidder might otherwise be eligible, then that bidder will have the option to either take the partial award or decline the award entirely.

Finally, the Energy Commission will notify the CPUC, IOU, and bidders of the availability of PGC funds within 30 days of receiving all data needed to conduct this evaluation. The Energy Commission will also notify the CPUC, IOU and winning bidders of the potential PGC award per winning bidder. The Energy Commission will approve the final PGC awards after the winning bidders have met all of their environmental review requirements.

Discussion and Rationale: SB 1038 directs the Energy Commission to award SEPs to renewable energy resources "selected by retail sellers to fulfill" their RPS obligations. SB 1078 requires the Energy Commission to "Allocate and award supplemental energy payments pursuant to [Public Utilities Code] Section 383.5 to eligible renewable energy resources to cover above-market costs of renewable energy." Further, SB 1078 states that, "the commission [CPUC] shall consult with the Energy Commission in calculating market prices ..." SEPs are based on the difference between the bid price and market price referent if the bid price exceeds the market price referent.

Once a utility completes its RPS procurement solicitation and selects winners, the CPUC will announce the market price referent. Pursuant to SB 1078, the CPUC shall review the results of a solicitation and accept or reject proposed contracts based on consistency with the utility's approved renewable procurement plan. Further, if the CPUC determines that the bid prices are elevated due to a lack of effective competition among bidders, the CPUC is required to direct the utilities to renegotiate such contracts or conduct a new solicitation.

The Energy Commission recognizes that execution of PPAs for winning bidders of an RPS procurement solicitation may depend upon assurance that the bidder will receive SEPs. Also, the CPUC decision to approve or deny contracts will be better informed if the Energy Commission has determined PGC availability. Consequently, it is important for the Energy Commission to make a timely determination that a bidder is eligible for

the RPS and SEPs, and that there are sufficient PGC funds to cover any SEPs needed by winning bidders.

However, the Energy Commission must ensure that all funding criteria are met before issuing a final funding award. The Energy Commission's requirements must be balanced with the need to assure parties that SEPs are available to meet bidders terms. Therefore, the Energy Commission will notify winning bidders of their SEP eligibility and the amount of PGC funds that are available to them.

The Energy Commission will be able to notify winning bidders of the potential PGC awards, but will not be able to approve final funding award agreements until a winning bidder has:

1. executed a PPA with the utility,
2. completed any required environmental review of its project under the National Environmental Policy Act and/or the California Environmental Quality Act (CEQA), and
3. submitted copies of its project's required environmental documents — certified final environmental impact report/statement, negative declaration, exemption letter, and so on — to the Energy Commission so that the Energy Commission may rely on and consider these documents pursuant to Section 15096(f) of the CEQA Guidelines (Title 14, California Code of Regulations, Division 6).

For projects already operational, the Energy Commission will only approve a final funding award agreement once the project developer has delivered the necessary environmental documents to the Energy Commission.

The Energy Commission recommends that the CPUC transmit information about the market price referent at the same time the CPUC reveals it to the utilities, and that the CPUC direct the utilities to transmit information on the utility-selected projects to the Energy Commission at same time this information is transmitted to the CPUC. This information should include the bid price, expected energy price, contract term, expected quantity of energy to be delivered, and other pertinent information for each of the projects selected by the utilities.

These recommendations are generally supported by Joint Principles developed by TURN and SDG&E, which call for utilities to provide relevant information to the Energy Commission at the time a PPA is submitted for CPUC approval so that the Energy Commission can determine the SEPs needed to support expected contract obligations. The Energy Commission does not intend to re-rank the utilities' least cost best fit ranking of bids.

The Joint Principles further recommend that the Energy Commission make a preliminary determination regarding the availability of PGC funds before CPUC action approving any contracts. The Energy Commission agrees that it should make an initial determination on PGC availability based on the market price referent established by

CPUC, the results of the IOU's procurement solicitation, and the Energy Commission's own evaluation of the winning bidders' eligibility for the RPS and SEPs.

To make such a determination, the Energy Commission will first verify that each winning bidder was certified or pre-certified as eligible for the RPS and the SEP. For each winning bidder with a bid price higher than the market price referent, the Energy Commission will calculate the amount of PGC funds needed to fund the SEP. This evaluation will depend on the bid price, the market price referent, and the expected energy deliveries from the bidder.

Comments from Calpine Corporation, CalWEA, SDG&E and Vulcan Power Company supported allocating PGC funds in order of the least-cost-best-fit ranking in the event that PGC funding is not sufficient to meet the demand of a solicitation. CalWEA added that if the funds are sufficient to partially cover the SEPs of a bidder, then the facility, together with the contracting retail seller, should have the option of down-sizing the contract or accepting a smaller award. CalWEA further stated that if the award is declined, it should go to the next least-cost facility. The Energy Commission agrees with these comments.

PG&E, TURN, and SDG&E all commented on the need to coordinate the processes of certifying eligible renewable resources, selecting winning bidders, and awarding SEPs. PG&E and SDG&E stated that "sequencing the utility and the CEC processes needs to be seamless in order to facilitate an effective and efficient RPS implementation." The Energy Commission agrees and believes it has proposed an appropriate sequence.

## **Flexibility in Guidebook Development**

**Decision:** The Energy Commission will preserve flexibility in developing guidebooks and implementing the RPS to reflect ongoing efforts at the CPUC as well as to respond to market developments.

**Discussion and Rationale:** The Energy Commission recognizes that implementing the RPS will require further public input to develop the details. Also, the CPUC's rules for implementing the RPS are still under development and will continue to be refined over time, which reinforces the need for flexibility in the guidebook development process.

## **Deferred Issues**

The Energy Commission has deferred decisions on several issues. First, any decision on requirements for public works projects must be deferred because the Energy Commission has no say in how the public works/prevaling wage issue will be resolved; the Energy Commission will be required to apply rules determined by the Department of Industrial Relations.

Several issues require a decision or guidance from the CPUC. For example, SB 1038 provides the Energy Commission the ability to establish caps on SEPs "designed to provide for a viable energy market capable of achieving" the RPS goals. However,

design of any caps on SEPs will depend on the implementation of the least-cost-best-fit bid ranking criteria developed by the CPUC. The Energy Commission defers any decision on any cap structure until stakeholders have an opportunity to review CPUC Decision 03-06-071 and provide comments on the decision's impact on SEP caps.

SB 1038 also states that “the Energy Commission may provide preference to projects that provide tangible demonstrable benefits to communities with a plurality of minority or low-income populations.” Again, the Energy Commission defers its decision until stakeholders have an opportunity to review CPUC Decision 03-06-071 and provide comments on implementation of this language.

SB 1038 directs the Energy Commission to manage SEP funds “in an equitable manner in order for retail sellers to meet their” RPS obligation. Similarly, SB 1078 directs the CPUC to institute rulemakings to determine the manner in which ESPs and CCAs will participate in the RPS. Because those proceedings are not yet underway, the Energy Commission defers any decision on funding allocations between providers or classes of providers until the CPUC's proceedings are complete.

## Certification

SB 1078 directs the Energy Commission to “certify eligible renewable energy resources that it determines meet the criteria as an eligible renewable energy resource.” The Energy Commission currently registers renewable energy resources for several other purposes, including the Renewable Energy Program established under SB 90 and the Existing Renewable Facilities Program established under SB 1038. To certify eligible renewable energy resources, the Energy Commission must consider the following:

- certification and registration eligibility,
- certification data, documentation, and verification, and
- certification amendments.

## Certification and Registration Eligibility

Decision: If a renewable energy resource sells energy to a retail seller to meet an RPS obligation, the renewable energy resource must be certified by the Energy Commission as meeting the eligibility criteria defined in the Energy Commission's *Renewable Portfolio Standard: Decision on Phase 1 Implementation Issues*. Projects proposed, under development, or in construction are eligible for provisional or “pre-” certification based on the owners' self-certification of the proposed project, subject to further verification once the project has been completed.

Renewable energy resources that meet the definition of renewable for the purposes of the Renewable Energy Program or the Power Source Disclosure Program but that do not meet the definition of an eligible renewable energy resource for the purposes of the RPS may continue to be “registered,” rather than “certified.”

Discussion and Rationale: In their comments, SDG&E stated that the Energy Commission should establish a procedure that would allow facilities to be certified before submitting bids, and that in no event should certification occur after the utility submits contracts to the CPUC for approval. SDG&E also asserted that a utility must have a final assessment from the Energy Commission as to whether a facility is eligible for the RPS to ensure that the utility takes actions that will satisfy its annual procurement target. The Energy Commission agrees and believes that pre-certification is necessary to prevent ambiguity about the eligibility of proposed renewable energy resources that respond to RPS solicitations.

CEI commented that the Energy Commission should differentiate between “registration,” “certification,” and “verification.” According to CEI, “registration” simply generates a list of participants and does not involve great detail for each registered renewable generator. “Certification” generates a more limited and detailed list of generators, and should be subject to independent third-party audits paid for by generators if and when the Energy Commission deems the audit to be necessary to confirm RPS eligibility. “Verification” is the enforcement step whereby the Energy Commission is mandated and empowered to ensure credibility. In its comments, CEI supported the idea of establishing eligibility before the issuance of a Request for Offers, with eligibility for the RPS documented in a generator’s bid submission.

PG&E maintained that certification should be mandatory for all RPS participants and also argued that every “eligible renewable energy resource,” as defined by PUC section 399.12(a), in the state should be registered. PG&E’s argument was that even if generation from those facilities is not intended for RPS participation today, it could be in the future.

The Energy Commission agrees with CEI’s and PG&E’s comments.

## **Certification Data, Documentation, and Verification**

Decision: The Energy Commission will use a self-certification procedure for renewable energy resources. To verify the accuracy of self-certification claims, the Energy Commission will do the following:

1. institute an audit procedure to conduct spot checks of the documentation provided for self-certification,
2. post information on the Energy Commission website to support industry self-policing, and
3. retain the right to request additional documentation at any time to verify certification.

The Energy Commission will accept documentation from other government agencies, where applicable, for purposes of self-certification.

Discussion and Rationale: These measures will assure the integrity of the RPS program and ensure that the RPS goals are met in accordance with the statutes. The Energy Commission wishes to maximize the effectiveness of the verification efforts without imposing burdensome costs on participants. A spot-check audit procedure provides the necessary assurances without imposing unreasonable costs. Furthermore, posting information publicly will help to make the certification process as transparent as possible and ensure that the Energy Commission receives accurate information. In addition, making the data public allows other parties to conduct their own check of the information so that they may notify the Energy Commission of any misrepresentations.

Certification data requirements will vary by renewable energy resource type, based on the eligibility criteria for RPS compliance established by the *Renewable Portfolio Standard: Decision on Phase 1 Implementation Issues*. For example, fuel limitations for biomass facilities require documentation irrelevant to a wind generator. In verbal comments at the May 12 and 13, 2003 staff workshop, IEP proposed that verification of eligible fuel for a biomass generator could be based on self-certification by the fuel suppliers, submitted under penalty of perjury.

PG&E argued that certification should be enforced through periodic reporting and random site audits, but also stated that participants and regulators must be mindful not to overburden enforcement resources or cause unreasonable delays in certifying and verifying renewable generation. PG&E stressed that the rules for the application and certification process should be as straightforward as possible so as not to discourage participation.

In regards to data collection, CEI recommended that the Energy Commission use existing data streams and databases whenever possible, including the generator's permit-related environmental submissions. CEI further maintained that the Energy Commission should determine who has legal oversight for each specific eligibility criterion, and that if no other agency has legal responsibility for oversight, interagency agreements may be needed.

The Energy Commission agrees that penalties for non-compliance are unnecessary beyond those already included in the PPA between the retail seller and the renewable energy resource.

## **Certification Amendments**

Decision: Certified facilities must notify the Energy Commission in a timely manner of any material changes in information previously submitted to the Energy Commission, and that facilities failing to do so should be subject to disqualification. Certification must be renewed every year to capture any facility changes and to confirm that all certified renewable energy resources remain eligible for the RPS. In addition, if a certified or pre-certified entity does not respond to the Energy Commission's request for an information update in a timely manner, it will risk losing its certification status.



If there are any changes to the status of a facility's certification, the new information will be posted on the Energy Commission's website and any affected utility contracting with that facility will be promptly notified.

Discussion and Rationale: SDG&E submitted comments asserting that the Energy Commission should develop a system to verify a facility's continuing eligibility during the term of its participation in the RPS. The Energy Commission agrees that data submitted in the application for certification may change over the duration of the RPS program. While some items will remain constant, such as the location of the facility, other items such as fuel usage, facility size, or facility ownership may change, requiring more frequent verification. Information submitted in the certification process will document a facility's eligibility for the RPS, but it is vital to the program to ensure that such records are current and accurate. SDG&E also recommended that the Energy Commission notify the utilities and publicly post any changes in the certification status of an eligible resource. The Energy Commission agrees and intends to make changes to a facility's eligibility status publicly available as quickly as possible, and to specifically notify any affected IOU.

## Accounting System

SB 1078 requires the Energy Commission to design and implement an accounting system to verify retail sellers' compliance with the RPS. The primary purpose of the proposed accounting system is to:

1. verify compliance with the RPS by retail sellers,
2. ensure that renewable energy output is counted only once for the purpose of meeting the RPS of this state or any other state, and
3. verify retail product claims in this state or any other state.

According to SB 1038, a secondary purpose of the proposed accounting system should be to track the amount of renewable electricity produced and sold by SEP-eligible renewable generators on a monthly basis. Because the *Renewable Portfolio Standard: Decision on Phase I Implementation Issues* provides that out-of-state renewable power be eligible for the RPS, the accounting system must also be able to verify generation and contracts from out-of-state facilities.

This section covers the following:

- recommended accounting systems
- the interim accounting system
- the long-term accounting system
- required participants in the accounting system
- long-term system source of data
- transactions tracked in the electronic accounting system
- type of information tracked by the electronic accounting system

- public access to electronic system data
- in-state delivery requirement
- participating in a WECC accounting system
- determining “baseline” designation

## Recommended Accounting Systems

Decision: The Energy Commission will (1) use an interim contract-path accounting system to verify RPS compliance for 2003 and 2004; and (2) develop a long-term electronic-path accounting system in coordination with the Western Governors’ Association (WGA) that can record renewable generation and transactions through the system starting in 2005 and meet the needs specified in SB 1078:

1. verify compliance with the RPS by retail sellers,
2. ensure that renewable energy output is counted only once to meet the RPS of this state or any other state, and
3. verify retail product claims in this state or any other state.

For both the interim and long-term systems, in-state and out-of-state renewable energy generators that are eligible for the RPS must first be certified by the Energy Commission.

Discussion and Rationale: Based on comments received at the May 13, 2003 workshop regarding evaluating options for verifying RPS compliance, the Committee examined two general categories of RPS accounting systems: contract-path and electronic-path accounting. There were no written or oral comments suggesting any other accounting methods for either the interim or long-term accounting systems.

For the purposes of this decision, a *Contract-path Accounting System* refers to an accounting methodology whereby individual contracts and financial settlement data are used to verify renewable purchases. Such a system usually involves some sort of manual review of contracts and receipts, although the information may be entered into a database or other electronic format.

An *Electronic Accounting System* refers to a system whereby financial settlements data are automatically entered into an electronic system, eliminating or minimizing the need to do manual review of contracts or receipts. An electronic accounting system is based on creating renewable certificates for each increment of electricity generated. The CPUC is currently considering whether these certificates should be allowed to be traded separately from the underlying electricity.

The immediate need for the accounting system is to verify energy transactions for 2003 and 2004. For an electronic system even to be a possibility for 2003, it would have had to have been in place January 1, 2003. Likewise, for an electronic accounting system to be available for 2004, it would have to be in place by January 1, 2004. Based on oral

comments received from Automated Power Exchange (APX, Inc.) and Clean Power Markets (CPM) at the May 13, 2003 staff workshop, software design for even a relatively simple electronic accounting system can take about six months to develop. Consequently, the Energy Commission will use a contract-path system for the interim accounting system while the long-term electronic-path accounting system is being developed.

The Energy Commission's decisions regarding the interim and long-term accounting systems are described below.

### **Interim Accounting System**

**Decision:** The Energy Commission will adapt the verification process used for its existing Power Source Disclosure Program to verify claims made with regards to RPS obligations, on an interim basis, for compliance years 2003 and 2004.

**Discussion and Rationale:** Adapting the Power Source Disclosure Program is the most feasible way to ensure that the statutory requirements of SB 1078 and SB 1038 are fulfilled. Under this program, retail providers submit annual reports to verify their retail product claims. These reports are examined for discrepancies by Energy Commission staff and an independent third party auditor using a previously-established protocol for agreed-upon procedures. An auditor's report is required for all retail providers, including the IOUs, with the exception of municipal utilities with only one product.

The Energy Commission believes that the verification process for the Power Source Disclosure Program can be modified relatively easily and that a modified protocol for agreed-upon procedures can be ready to verify 2003 transactions by the first quarter of 2004.

The adaptation requires the Energy Commission to revise its current regulations for the Power Source Disclosure Program (Title 20, California Code of Regulations, sections 1390, et seq.), modify the existing Power Source Disclosure forms, and create a new protocol for agreed-upon procedures to instruct independent third-party auditors how to verify RPS claims in addition to Power Source Disclosure claims. The Energy Commission will amend the protocol for agreed-upon procedures already in place to accommodate verifying RPS obligations. Once the regulations are amended, the Energy Commission will develop guidelines based on the amended regulations to govern the interim accounting system.

The Power Source Disclosure forms will be modified to allow entities to verify their compliance with the RPS, including, but not limited to, the following:

- demonstrating that the retail seller purchased enough renewable electricity to meet its RPS obligation,
- demonstrating that the renewable electricity purchased is eligible under the California RPS and is certified by the RPS program,

- attesting that the retail seller's contracts include all environmental and renewable energy attributes associated with the production of electricity, or "RECs," as defined by CPUC Decision 03-06-071. The attestation would ensure that these are not "energy-only" contracts, unless otherwise deemed appropriate by the CPUC, and
- attestations ensuring that the generator is not double-selling renewable electricity or its generation-related attributes, or RECs, to another party, including meeting the RPS requirements of another state.

The Energy Commission considered whether the interim accounting system should be designed to accommodate verification of other claims or voluntary activities. At this time, the Power Source Disclosure Program forms will be modified only enough to meet the statutory requirements under SB 1078 and SB 1038. If retail sellers want to verify other claims or activities, they are free to hire an auditor to verify these claims or activities. There is no need for the Energy Commission to devote resources to developing an interim accounting protocol for such claims, or trying to anticipate what kinds of claims retail sellers might want to voluntarily verify.

The Energy Commission received a number of comments regarding the advantages and disadvantages of both contract- and electronic-path accounting systems. SDG&E commented that the interim system should be a contract-path accounting system based on "metered data scaled down from the scheduling coordinators," presumably to account for line losses. CEI also was supportive of an interim contract-path accounting methodology. Similarly, PG&E indicated that it was comfortable that current sources of data can be used in a contract-path accounting and verification system to meet the state's interim needs.

CPM suggested that an interim system should be a simple, flexible electronic system that will provide lessons for the development of the long-term system while allowing retail sellers to gain experience using an electronic system. CPM believed that such a system could be developed cost-effectively. Although the Energy Commission agrees with CPM that an electronic system might be a superior option, because of time constraints the Energy Commission recommends adapting the verification process for the Power Source Disclosure Program for the compliance years 2003 and 2004.

Powerex Corporation asserted that a contract-path accounting system would be easier to implement if the Energy Commission simply allowed companies to maintain records and to have those records available to an independent auditor. The Energy Commission believes that this approach will not provide the level of verification required to fulfill the statutory requirements under SB 1078, and, therefore, does not recommend using this approach.

### **Long-term Accounting System**

Decision: The Energy Commission will develop a long-term electronic accounting system for the compliance year 2005 and beyond that will be able to meet the statutory requirements of SB 1078 and SB 1038. The electronic accounting system for RPS

accounting will issue renewable energy certificates (RECs) for every megawatt-hour (mWh) generated by eligible renewable generators. Generators selling renewable electricity for RPS purposes must be account holders in the accounting system. Generators that are not eligible for the RPS but that want to participate in the electronic accounting system may apply to be account holders. The details of applying for an account will be defined during the design of the electronic accounting system.

The long-term system will be designed so that a unique electronic record — known as a REC — will be created for each mWh of renewable energy generated by a registered generator. Once created, the REC will be deposited into the generator's account. IOUs and other market participants such as CCAs, ESPs, publicly-owned utilities, generators, and intermediaries can transfer RECs between accounts, for example from the generator to a retail seller with whom the generator has a contract, and use the RECs as a mechanism to verify that a retail seller has acquired enough renewable energy to fulfill their RPS obligation. Both the buyer and the seller must confirm the transaction before it is officially entered into the system (e.g. quantity and whether bundled or unbundled with energy). Once a REC is used to satisfy an RPS requirement, it will be marked as "retired" so that it cannot be resold or claimed by any other party, or used for any other purpose.

Decisions about whether and under what conditions RECs can be traded separately from electricity under the California RPS are the subject of ongoing deliberations at the CPUC. The Energy Commission does not pre-judge those decisions here, but does note that it envisions the long-term electronic system being able to meet the state's RPS verification needs in either instance.

Discussion and Rationale: A long-term electronic-path accounting system will be adopted for a variety of reasons, including:

- ease of administration
- low long-term costs
- assurances against double counting
- facilitation of ESP participation
- support of secondary purposes

Ease of Administration: Electronic accounting systems are easy to administer and use because they minimize the need to manually review contracts or rely heavily on attestations. Renewable purchases are easily tracked by a review of the electronic accounts. Unlike contract path systems, there is no need to follow the path of electricity contracts to determine compliance.

As the number of market participants increases, the ease of administering an electronic accounting system becomes even more important. Based on the Energy Commission's experience in administering and operating contract path accounting systems for the Customer Credit Subaccount and the Power Source Disclosure Program, it would be too challenging to administer a contract path verification system for the RPS, especially since the RPS applies to IOUs and is also expected to apply to ESPs and CCAs.

**Low Long-Term Costs:** SDG&E, the Center for Energy Efficiency and Renewable Technologies (CEERT), and CPM commented that an electronic system would be less labor intensive to implement and more efficient in the long run for California. The Alliance of Retail Energy Markets (AREM) maintained that the electronic system would be no more costly than a contract-path system for the state. The Energy Commission agrees with these comments. Although establishing an electronic system may initially be more costly, the ongoing costs and staff requirements are low. An electronic accounting system will, over time, be less costly to retail sellers than conducting a detailed annual audit.

**Assurance of No Double Counting:** AREM, SDG&E, and CPM commented that a REC-based electronic system is superior to a contract-path approach for preventing “double counting” of renewable energy output. In contrast to a contract-path approach, an electronic accounting system would enable regulators and potential buyers to easily and relatively conclusively determine whether or not the output of a given renewable resource has been counted toward a retail seller’s RPS obligations.

The Energy Commission agrees that an electronic accounting system is superior in preventing double counting. Since a single REC is generated for every unit of electricity generation, REC ownership establishes the property rights needed for suppliers to make credible claims. The electronic system provides a clear, consistent process for transferring that property right between parties. In contrast, a contract-path accounting system forces regulators to rely on paper contracts, attestations, and after-the-fact reviews. Assurance against double counting cannot be provided as firmly and securely as under an electronic accounting system.

**Facilitation of ESP Participation in the RPS:** AREM, TURN and CEERT commented that tradable RECs play a key role in enabling ESPs to comply with RPS requirements in other states in a cost-effective manner. Unlike utilities, few ESPs are in a position to enter into long-term contracts for renewable energy and capacity. The Energy Commission recognizes that whether RECs can be traded separately from electricity is a decision that will need to be determined in the later phase of this proceeding, and that unbundled RECs may not be allowed to satisfy RPS obligations. Nonetheless, it is reasonably clear that many ESPs will seek to rely on RECs purchased in the open market to satisfy their RPS obligations. An electronic system is best positioned to meet those potential needs in the future, and notes that the CPUC has made a similar judgment in Decision 03-06-071.

AREM commented that, in the event that the CPUC adopts rules for ESP and CCA participation in the RPS program earlier than mid 2004, the Energy Commission should attempt to accelerate the implementation of an electronic accounting system, rather than use a contract-path based accounting system. Although the Energy Commission recognizes AREM comments, it is not feasible to accelerate the implementation of the electronic tracking system.

**Supports Secondary Purposes:** The creation of an electronic accounting system may also have ancillary market benefits that are consistent with the CPUC and Energy Commission’s goal of increasing renewable generation in the state. These benefits may

come from ensuring credibility of voluntary renewable markets, and facilitating retail REC-only products and the verification of the renewable energy purchases of publicly owned utilities. By developing an electronic accounting system for RPS compliance, California will also be creating a system that may facilitate and expand other demands for renewable energy in, and potentially outside, the state. AReM, WGA, and other stakeholders at the workshop supported these secondary benefits.

Nearly all comments received were explicitly in favor of an electronic accounting system for the long term, and no comments were opposed. AReM, CEERT, SDG&E, CEI, CPM, TURN, and WGA all commented that the final system for accounting and verification should be a REC-based electronic accounting system. Powerex contended that they were not opposed to an electronic accounting system, though they indicated that if it focused solely on in-state generation, it could preclude out-of-state generators from competing fairly. They were supportive of a WECC-wide electronic accounting system.

Two parties, CEI and CPM, commented on the process for developing the details of the electronic accounting system. CEI stated that design of the details of the electronic accounting system requires an open stakeholder forum where participants feel empowered to work with the Energy Commission and CPUC. CPM noted that time is needed to reach general agreement on what a long-term system will look like. The Energy Commission agrees with both of these comments, and commits to working expeditiously with all interested parties. A workshop regarding the details of the accounting system is planned as part of Phase 3 of the RPS proceeding.

Several comments were received that focused on the specific design of the system. CEERT suggested that “California’s system be designed to ensure the following: 1) that a REC is only created when one unit of renewable energy is generated, 2) a REC is retired once it is used to meet the obligations of the RPS, and 3) a REC is treated in the first instance as a property right of the generator, to be expressly identified and transferred via contract.” SDG&E argued that the system should have an “open architecture that can accommodate future design and expansion. The electronic system should accommodate future enhancements such as a REC trading system.” CPM also maintained that the system should be designed with future expansion in mind, and that “It should be simple, flexible, and automated.” PG&E declared that the long-term system does not need to be designed to facilitate unbundling of environmental attributes or the trading of renewable energy credits and that there is no need to track or account for environmental attributes separately from the energy at this time.

The Energy Commission agrees with the general principles of flexibility and an open architecture for the accounting system, and intends to rely on these principles during the design process.

## **Required Participants in the Accounting System**

Decision: All of California’s IOUs, ESPs, and CCAs that are subject to the RPS will be required to participate in both the interim and final accounting system to verify their compliance with the law. Similarly, the Energy Commission will require all renewable

generators who receive SEPs, or sell their electricity or attributes to meet a retail seller's RPS obligations, to participate in the system. Such generators must also fully opt-in to the system, meaning that all of the output from their facilities must be tracked by the electronic accounting system.

The long-term system will be designed to allow other parties to participate in the electronic accounting system, such as publicly owned utilities, brokers, or any other market participants who wish to verify renewable transactions or provide proof of renewable purchases.

If the Energy Commission and the CPUC ultimately decide that renewable electricity generated by customer-sited generators is eligible for the RPS, the Energy Commission will develop a process to measure and verify the output from these generators. However, the Energy Commission defers any decision regarding the eligibility of these renewable generators until Phase 3 of the RPS proceeding, and invites further comment regarding the eligibility of customer-sited, grid-connected renewable generators as well as suggestions for how to measure and verify the output from these generators.

Discussion and Rationale: CEI and TURN commented that the accounting system should facilitate both mandatory and voluntary retail seller participation. The Energy Commission agrees that all market participants should be included early to increase support for the system among retail sellers not currently under a mandate to participate. In addition, this approach will remove barriers to such retail sellers voluntarily meeting the RPS. As importantly, the broader the participation in the system, the more assurance can be provided that double counting is not occurring.

CPM commented that all output from out-of-state generators who are selling to retail sellers to meet the California RPS must be tracked in the California system to avoid double counting. The Energy Commission agrees with this principle and extends it to all in-state generators as well. To meet the requirements of SB 1078 to "ensure that renewable energy output is counted only once for the purpose of meeting the renewable portfolio standard of this state or any other state," the state must know not only that a generator is selling its output to a California retail seller, but also to whom that power is sold.

It is conceivable that a California generator could be selling its renewable energy to meet another state's RPS. Therefore, the long-term system must be designed so that other states may use it, and so it can track all of the output from any generation unit participating in the electronic accounting system to ensure that no double selling occurs. Tracking all of the output will also allow buyers of the renewable generation to verify that they are receiving all of the RECs they have paid for, even if they are purchasing the generation as part of a voluntary initiative.

## **Long-term System Source of Data**

Decision: The electronic accounting system will use settlements data on generation and wholesale transactions. The system will maintain an electronic database and accounting



system with this information. If generation is not otherwise tracked through settlements data, but is still metered by local distribution companies, the generator or distribution company may self-report, provided that appropriate measures have been taken to ensure accuracy of the information.

The Energy Commission invites comments on how to verify the accuracy of self-reported power production data, including the accuracy of any independently owned metering equipment, and how to account for line losses for self-reported generation, if line loss calculations are required. The Energy Commission believes that the accuracy of self-reported information may be verified or corroborated in some instances using reports and information from other agencies.

Discussion and Rationale: CPM stated in its comments that the “system should use accurate meter readings from generators, as collected by the ISO [Independent System Operator], as the basis for an electronic accounting system. There should be consistent treatment of energy and RECs in terms of loss factors (GMMs).” CPM also maintained that out-of-state generators that participate in the accounting system “must agree, through force of law, that all of their output will be tracked and verified through the California system to avoid double-counting.”

The Energy Commission agrees with this assessment, and intends to use settlement quality data for several reasons. First, the data can be adjusted for line losses if needed, therefore providing a consistent and accepted practice for handling line losses in an electronic accounting system even though settlements may not all be occurring at the California Independent System Operator. Second, financial settlement data are universally accepted as the absolute measurement of generation and delivery of electricity, and provide an appropriate level of accuracy for an electronic accounting system.

CEI provided comments that customer-sited generation, whether or not grid-connected, should be able to participate in the system. IEP expressed concern in its comments about the credibility of self-reported generation. Other stakeholders at the workshop appeared more comfortable with engineering estimates and self-reported generation for customer-sited generation. Several stakeholders suggested that where possible, information from other agencies should be used to verify the accuracy of self-reported data. The Energy Commission defers discussion regarding the participation of customer-sited generators for RPS purposes to Phase 3 of the RPS proceeding, and welcomes further comment on the parameters of such participation.

## **Transactions Tracked in the Electronic Accounting System**

Decision: The electronic accounting system will initially track only renewable generation — both RPS-eligible and any non RPS-eligible renewables that wish to participate in the accounting system — but will be designed to be flexible enough to accommodate future verification of specific purchases of non-renewable generation.

Discussion and Rationale: SB 1078 requires that the Energy Commission's accounting system not only serve RPS compliance purposes, but also be used for "verifying retail product claims in this state or any other state." The Energy Commission interprets this language to mean that the accounting system, at a minimum, must also be used to verify compliance with the Energy Commission's Power Source Disclosure Program. However, retail sellers might make specific claims in the future regarding non-renewable purchases. Therefore, the electronic accounting system must be able to accommodate specific purchases of other types of generation.

In tracking non-renewable generation, there are essentially two types of electronic accounting systems: an open system and a closed loop system. An open system is usually voluntary and is only capable of tracking specific purchases and transactions specified by market participants. In contrast, a closed loop system tracks all generation attributes in a control area, has mandatory participation by all generators and market participants, and maintains a "conservation of attributes" by assigning attributes to non-specific power purchases.

The design of a closed loop system is also more complex and, in many ways, less flexible than the design of an open system. Many policy decisions are embedded in the design of a closed loop system, such as the NEPOOL GIS. Because of the mandatory nature of such a system, it would be difficult to get all the WECC states to agree on a single system design by early 2005. Based on the comments of the WGA, such a system also would not be compatible with the WGA effort.

The Energy Commission agrees with comments that the electronic tracking system should be flexible and have an open architecture and recommends that the electronic accounting system be designed to track specific purchases only, not non-specific, system power purchases.

## **Type of Information Tracked by the Electronic Accounting System**

Decision: Each REC will have an electronic record that contains a host of information about the generation attributes that would allow the Energy Commission and CPUC to determine that the REC qualifies for the RPS or other programs, where appropriate. RECs will be defined to be consistent with Decision 03-06-071, in collaboration with the Energy Commission.

Discussion and Rationale: The electronic accounting system will track the following generation characteristics of each REC, recognizing that the system may be designed to track additional characteristics not mentioned here:

- generator name
- generator ID number(s)
- generator location - city, state
- commissioning date of generator
- installed capacity of generator (updated annually)

- date of generation (for each mWh)
- fuel type used (updated annually)
- whether the facility qualifies as “incremental” geothermal
- whether the facility is eligible for SEPs
- if the REC is from out-of-state, whether the associated energy was part of a contract that is eligible for RPS purposes

In addition, the electronic accounting system will receive information on the total load served from load schedulers and will note this in retail sellers’ accounts.

Creating the designations of “SEP eligible” and “incremental geothermal” should not be construed as a decision that such designations are mutually exclusive. The Energy Commission is currently evaluating specific information that geothermal generators will have to submit to demonstrate that their generation qualifies as incremental geothermal and under what conditions it would qualify for SEPs.

CEI suggested that data included in the long-term system should be able to be accessed separately for California use, particularly data that impacts eligibility for state program monies, and coded so data can be sorted in different ways for analysis later. The Energy Commission agrees with this general principle, and has identified a starting list of minimum attributes that will be tracked, but a more detailed discussion of what specific generation information is to be included will take place in the process of system design. CEI also argued that information on the labor characteristics of a plant should be included in the accounting system, as well as an indication of whether specific attributes have been monetized or not. The Energy Commission welcomes further comment on these issues.

## **Public Access to Electronic System Data**

**Decision:** The data collected for the electronic system will be made available to the public, with the exception of data automatically categorized as confidential pursuant to the Energy Commission’s regulations on confidentiality (Title 20, California Code of Regulations, sections 2501 et. seq). If the data do not fall within one of the categories for automatic confidential designation, the information will be made available to the public unless the party seeks and obtains a confidential designation for the data pursuant to the Energy Commission’s regulations on confidentiality.

**Discussion and Rationale:** CEI maintained that “Clear rules of access must be established and maintained regarding competitive access to data.” The Energy Commission agrees that information falling within a category of automatic confidential designation not be publicly available. The remainder of the information will be publicly available, unless the party seeks and obtains a confidential designation for the data pursuant to the Energy Commission’s regulations.

## **In-State Delivery Requirement**

**Decision:** The Energy Commission will work with the California ISO and other stakeholders to determine the ability to verify whatever in-state delivery requirements are ultimately imposed.

**Discussion and Rationale:** At the May 5, 2003 Committee Hearing, the Committee called for further discussion on whether a requirement to deliver power into California should be adopted and, if so, how such a requirement should be implemented. Powerex commented that RECs generated in British Columbia, Canada should be eligible for California's RPS, and was indifferent to the energy delivery requirement as long as it allows bundling of RECs generated by British Columbia generators with WECC spot market power delivered to California. CEI maintained that "sales of energy and credits may be bundled for convenience or on demand, but that the accounting must occur independently for each, as separate data streams for separate commodities." CPM argued that "allowing RECs to be unbundled from the energy will facilitate broader retail seller compliance from ESPs and community aggregators." TURN commented in the workshop that a delivery requirement is desirable to ensure that Californians receive the air quality benefits of displacing in-state generation. CalWEA urged the Commission to consult with potential vendors of accounting systems, as they may have knowledge related to verification of energy delivery requirements. Other workshop participants noted that in-state delivery is a common requirement among states with an RPS.

## **Participating in a WECC Accounting System**

**Decision:** The Energy Commission staff will work with the WGA to develop a regional accounting system that can, at a minimum, exchange data with other states in the WECC to prevent double counting.

**Discussion and Rationale:** In June 2002, WGA passed a resolution that supports the "establishment of a single institution in the West that will issue, track, and oversee REC trading," and the "creation of an independent, regional generation accounting system to provide data necessary to substantiate the number of megawatt hours generated from renewable energy sources and support verification, accounting and trading of RECs" (Western Governors' Association Policy Resolution 03-03, February 25, 2003, page 5).

Since the passage of this resolution, several Working Group meetings — in which Energy Commission staff participated — have occurred to move forward on developing such a system. WGA has also contracted with the Center for Resource Solutions to construct a needs assessment survey to get input from key stakeholders. The survey would also identify the regulatory and commercial functions in the Western Interconnect that would be served by a certificates-based, western renewable energy generation information system. Once WGA receives the results from the needs assessment survey, WGA will develop the conceptual framework for such a system.

The majority of stakeholders at the May 13, 2003 workshop supported the idea of a regional accounting system, especially with respect to preventing double counting.

Powerex, WGA, and the majority of workshop participants supported developing a WECC-wide electronic accounting system. Powerex commented that a WECC-wide accounting system would foster more competition for RECs, which would lower the costs of renewable energy as a whole and benefit California.

TURN expressed concern about the costs of a regional system versus one that serves California's needs. Workshop participants commented that existing electronic accounting systems are self-supporting through user fees. APX stated that the major costs of developing a WECC-wide electronic accounting system would be establishing a data interface with each of the settlement systems in the West. PG&E cautioned that California ratepayers should not bear any system costs beyond what is necessary to ensure RPS compliance and that it is inappropriate for California ratepayers to pay for systems needed by other states or by a private voluntary REC trading market. PG&E also agreed that the system should be self-supporting and supports the idea that each participating state could pay its own state's costs of developing a data interface with its settlement systems.

## **Determining “Baseline” Designation**

**Decision:** If the CPUC, in collaboration with the Energy Commission, determines it is necessary to track whether a facility is “baseline” or “additional procurement,” the electronic accounting system should add these designations in addition to the other designations of “SEP eligible” and “incremental geothermal.”

**Discussion and Rationale:** Several comments were made in the staff workshop regarding whether the electronic system should identify that facilities are “baseline” or “additional procurement.” At this time, it is not clear if the electronic accounting system will need to include a designation for “baseline” or “additional procurement.” However, if the CPUC and Energy Commission ultimately decide this information is necessary, the accounting system will include a field associated with each generator that indicates whether the generator qualifies as a “baseline” or “additional procurement” facility.

If this designation is included, then any REC issued for a California generation facility would identify whether the REC is “baseline” or not. The designation would be input to the accounting system from the Energy Commission generator certification process and would be updated if a facility changed status.

# **Appendix A**

## **PARTICIPANTS IN RPS PHASE 2 IMPLEMENTATION PROCEEDING**

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Agland Energy Services  
Alliance for Retail Energy Markets  
Bren School UC Santa Barbara  
California Farm Bureau Federation  
California Independent System Operator  
California Wind Energy Association  
Calpine Corporation  
Center for Energy Efficiency and  
Renewable Technologies  
Chateau Energy, Inc.  
Clean Power Markets, Inc.  
Heschong Mahone Group, Inc.  
Independent Energy Producers  
Association  
National Biodiesel Board  
Natural Resources Defense Council

O'Connor Consulting Services, Inc.  
Pacific Gas & Electric Company  
Powerex Corp  
PPM Energy  
Renewable Energy, Inc.  
San Diego Gas & Electric Company  
Solargenix  
T<sup>2</sup> and Associates  
The Utility Reform Network  
Theroux Environmental  
Vulcan Power  
World Water Corporation  
Xenergy

# Appendix B

## RELEVANT STATUTORY LANGUAGE

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### Senate Bill 1078 (Sher, Statutes of 2002, Chapter 516)

Public Utilities Code

Article 16. California Renewables Portfolio Standard Program

399.11. The Legislature finds and declares all of the following:

(a) In order to attain a target of 20 percent renewable energy for the State of California and for the purposes of increasing the diversity, reliability, public health and environmental benefits of the energy mix, it is the intent of the Legislature that the California Public Utilities Commission and the State Energy Resources Conservation and Development Commission implement the California Renewables Portfolio Standard Program described in this article.

(b) Increasing California's reliance on renewable energy resources may promote stable electricity prices, protect public health, improve environmental quality, stimulate sustainable economic development, create new employment opportunities, and reduce reliance on imported fuels.

(c) The development of renewable energy resources may ameliorate air quality problems throughout the state and improve public health by reducing the burning of fossil fuels and the associated environmental impacts.

(d) The California Renewables Portfolio Standard Program is intended to complement the Renewable Energy Program administered by the State Energy Resources Conservation and Development Commission and established pursuant to Sections 383.5 and 445.

399.12. For purposes of this article, the following terms have the following meanings:

(a) "Eligible renewable energy resource" means an electric generating facility that is one of the following:

(1) The facility meets the definition of "in-state renewable electricity generation technology" in Section 383.5.

(2) A geothermal generation facility originally commencing operation prior to September 26, 1996, shall be eligible for purposes of adjusting a retail seller's baseline quantity of eligible renewable energy resources except for output certified as incremental geothermal production by the Energy Commission, provided that the incremental output was not sold to an electrical corporation under contract entered into prior to September 26, 1996. For each facility seeking certification, the Energy Commission shall determine historical production trends and establish criteria for measuring incremental geothermal production that recognizes the declining output of existing steamfields and the contribution of capital investments in the facility or wellfield.

(3) The output of a small hydroelectric generation facility of 30 megawatts or less procured or owned by an electrical corporation as of the date of enactment of this article shall be eligible only for purposes of establishing the baseline of an electrical corporation pursuant to paragraph (3) of subdivision (a) of Section 399.15. A new hydroelectric facility is not an eligible renewable energy resource if it will require a new or increased appropriation or diversion of water under Part 2 (commencing with Section 1200) of Division 2 of the Water Code.

(4) A facility engaged in the combustion of municipal solid waste shall not be considered an eligible renewable resource unless it is located in Stanislaus County and was operational prior to September 26, 1996. Output from such facilities shall be eligible only for the purpose of adjusting a retail seller's baseline quantity of eligible renewable energy resources.

(b) "Retail seller" means an entity engaged in the retail sale of electricity to end-use customers, including any of the following:

(1) An electrical corporation, as defined in Section 218.

(2) A community choice aggregator. The commission shall institute a rulemaking to determine the manner in which a community choice aggregator will participate in the renewables portfolio standard subject to the same terms and conditions applicable to an electrical corporation.

(3) An electric service provider, as defined in Section 218.3 subject to the following conditions:

(A) An electric service provider shall be considered a retail seller under this article for sales to any customer acquiring service after January 1, 2003.

(B) An electric service provider shall be considered a retail seller under this article for sales to all its customers beginning on the earlier of January 1, 2006, or the date on which a contract between an electric service provider and a retail customer expires. Nothing on this subdivision may require an electric service provider to disclose the terms of the contract to the commission.

(C) The commission shall institute a rulemaking to determine the manner in which electric service providers will participate in the renewables portfolio standard. The electric service provider shall be subject to the same terms and conditions applicable to an electrical corporation pursuant to this article. Nothing in this paragraph shall impair a contract entered into between an electric service provider and a retail customer prior to the suspension of direct access by the commission pursuant to Section 80110 of the Water Code.

(4) "Retail seller" does not include any of the following:

(A) A corporation or person employing cogeneration technology or producing power consistent with subdivision (b) of Section 218.

(B) The Department of Water Resources acting in its capacity pursuant to Division 27 (commencing with Section 80000) of the Water Code.

(C) A local publicly owned electrical utility as defined in subdivision (d) of Section 9604.

(c) "Renewables portfolio standard" means the specified percentage of electricity generated by eligible renewable energy resources that a retail seller is required to procure pursuant to Sections 399.13 and 399.15.

399.13. The Energy Commission shall do all of the following:

(a) Certify eligible renewable energy resources that it determines meet the criteria described in subdivision (a) of Section 399.12.

(b) Design and implement an accounting system to verify compliance with the renewables portfolio standard by retail sellers, to ensure that renewable energy output is counted only once for the purpose of meeting the renewables portfolio standard of this state or any other state, and for verifying retail product claims in this state or any other state. In establishing the guidelines governing this system, the Energy Commission shall collect data from electricity market participants that it deems necessary to verify compliance of retail sellers, in accordance with the requirements of this article and the California Public Records Act (Chapter 3.5 (commencing with Section 6250) of Division 7 of Title 1 of the Government Code). In seeking data from electrical corporations, the Energy Commission shall request data from the commission. The commission shall collect data from electrical corporations and remit the data to the Energy Commission within 90 days of the request.

(c) Allocate and award supplemental energy payments pursuant to Section 383.5 to eligible renewable energy resources to cover above-market costs of renewable energy.



## **Senate Bill 1038 (Sher, Statutes of 2002, Chapter 515)**

### **Public Utilities Code**

383.5. (a) It is the intent of the Legislature in establishing this program, to increase the amount of renewable electricity generated per year, so that it equals at least 17 percent of the total electricity generated for consumption in California.

(b) As used in this section, the following terms have the following meaning:

(1) "In-state renewable electricity generation technology" means a facility that meets all of the following criteria:

(A) The facility uses biomass, solar thermal, photovoltaic, wind, geothermal, fuel cells using renewable fuels, small hydroelectric generation of 30 megawatts or less, digester gas, municipal solid waste conversion, landfill gas, ocean wave, ocean thermal, or tidal current, and any additions or enhancements to the facility using that technology.

(B) The facility is located in the state or near the border of the state with the first point of connection to the Western Electricity Coordinating Council (WECC) transmission system located within this state.

(C) For the purposes of this subdivision, "solid waste conversion" means a technology that uses a noncombustion thermal process to convert solid waste to a clean burning fuel for the purpose of generating electricity, and that meets all of the following criteria:

(i) The technology does not use air or oxygen in the conversion process, except ambient air to maintain temperature control.

(ii) The technology produces no discharges of air contaminants or emissions, including greenhouse gases as defined in Section 42801 of the Health and Safety Code.

(iii) The technology produces no discharges to surface or groundwaters of the state.

(iv) The technology produces no hazardous wastes.

(v) To the maximum extent feasible, the technology removes all recyclable materials and marketable green waste compostable materials from the solid waste stream prior to the conversion process and the owner or operator of the facility certifies that the those materials will be recycled or composted.

(vi) The facility at which the technology is used is in compliance with all applicable laws, regulations, and ordinances.

(vii) The technology meets any other conditions established by the State Energy Resources Conservation and Development Commission.

(viii) The facility certifies that any local agency sending solid waste to the facility is in compliance with Division 30 (commencing with Section 40000) of the Public Resources Code, has reduced, recycled, or composted solid waste to the maximum extent feasible, and shall have been found by the California Integrated Waste Management Board to have diverted at least 30 percent of all solid waste through source reduction, recycling and composting.

(d) (1) Fifty-one and one-half percent of the funds collected pursuant to paragraph (6) of subdivision (c) of Section 381, shall be used for programs designed to foster the development of new in-state renewable electricity generation technology facilities, and to secure for the state the environmental, economic, and reliability benefits that continued operation of those facilities will provide.

(2) Any funds used for new in-state renewable electricity generation technology facilities pursuant to this subdivision shall be expended in accordance with the report, subject to all of the following requirements:

(A) In order to cover the above market costs of renewable resources as approved by the commission and selected by retail sellers to fulfill their obligations under Article 16 (commencing with Section 399.11), the Energy Commission shall award funds in the form of supplemental energy payments, subject to the following criteria:

(i) The Energy Commission may establish caps on supplemental energy payments. The caps shall be designed to provide for a viable energy market capable of achieving the goals of Article 16 (commencing with Section 399.11). The Energy Commission may waive application of the caps to accommodate a facility, if it is demonstrated to the satisfaction of the Energy Commission, that operation of the facility would provide substantial economic and environmental benefits to end use customers subject to the funding requirements of Section 381.

(ii) Supplemental energy payments shall be awarded only to facilities that are eligible for funding under this subdivision.

(iii) Supplemental energy payments awarded to facilities selected by an electrical corporation pursuant to Article 16 (commencing with Section 399.11) shall be paid for the lesser of 10 years, or the duration of the contract with the electrical corporation.

(iv) The Energy Commission shall reduce or terminate supplemental energy payments for projects that fail either to commence and maintain operations consistent with the contractual obligations to an electrical corporation, or that fail to meet eligibility requirements.

(v) Funds shall be managed in an equitable manner in order for retail sellers to meet their obligation under Article 16 (commencing with Section 399.11).

(B) The Energy Commission may determine as part of a solicitation, that a facility that does not meet the definition of "in-state renewable electricity generation technology" facility solely because it is located outside the state, is eligible for funding under this subdivision if it meets both of the following requirements:

(i) It is located so that it is or will be connected to the Western Electricity Coordinating Council (WECC) transmission system.

(ii) It is developed with guaranteed contracts to sell its generation to end use customers subject to the funding requirements of Section 381, or to marketers that provide this guarantee for resale of the generation, for a period of time at least equal to the amount of time it receives incentive payments under this subdivision.

(C) Facilities that are eligible to receive funding pursuant to this subdivision shall be registered in accordance with criteria developed by the Energy Commission and those facilities may not receive payments for any electricity produced that has any of the following characteristics:

(i) Is sold under an existing long-term contract with an existing in-state electrical corporation if the contract includes fixed energy or capacity payments, except for that electricity that satisfies the provisions of subparagraph (C) of paragraph (1) of subdivision (c) of Section 399.6.

(ii) Is used onsite or is sold to customers in a manner that excludes competitive transition charge payments, or is otherwise excluded from competitive transition charge payments.

(iii) Is produced by a facility that is owned by an electrical corporation or a local publicly owned electric utility as defined in subdivision (d) of Section 9604.

(iv) Is a hydroelectric generation project that will require a new or increased appropriation of water under Part 2 (commencing with Section 1200) of Division 2 of the Water Code.

(D) Eligibility to compete for funds or to receive funds shall be contingent upon having to sell the output of the renewable electricity generation facility to customers subject to the funding requirements of Section 381.

(E) The Energy Commission may require applicants competing for funding to post a forfeitable bid bond or other financial guaranty as an assurance of the applicant's intent to move forward expeditiously with the project proposed. The amount of any bid bond or financial guaranty may not exceed 10 percent of the total amount of the funding requested by the applicant.

(F) In awarding funding, the Energy Commission may provide preference to projects that provide tangible demonstrable benefits to communities with a plurality of minority or low-income populations.

(3) Repowered existing facilities shall be eligible for funding under this subdivision if the capital investment to repower the existing facility equals at least 80 percent of the value of the repowered facility.

(4) Facilities engaging in the combustion of municipal solid waste or tires are not eligible for funding under this subdivision.

(5) Production incentives awarded under this subdivision prior to January 1, 2002, shall commence on the date that a project begins electricity production, provided that the project was operational prior to January 1, 2002, unless the Energy Commission finds that the project will not be operational prior to January 1, 2002, due to circumstances beyond the control of the developer. Upon making a finding that the project will not be operational due to circumstances beyond the control of the developer, the Energy Commission shall pay production incentives over a five-year period, commencing on the date of operation, provided that the date that a project begins electricity production may not extend beyond January 1, 2007.

(6) Facilities generating electricity from biomass energy shall be considered an in-state renewable electricity generation technology facility to the extent that they certify to the satisfaction of the Energy Commission that fuel utilization is limited to the following:

(A) Agricultural crops and agricultural wastes and residues.

(B) Solid waste materials such as waste pallets, crates, dunnage, manufacturing, and construction wood wastes, landscape or right-of-way tree trimmings, mill residues that are directly the result of the milling of lumber, and rangeland maintenance residues.

(C) Wood and wood wastes that meet all of the following requirements:

(i) Have been harvested pursuant to an approved timber harvest plan prepared in accordance with the Z'berg-Nejedly Forest Practice Act of 1973 (Ch. 8 (commencing with Sec. 4511), Pt. 2, Div. 4, P.R.C.).

(ii) Have been harvested for the purpose of forest fire fuel reduction or forest stand improvement.

(iii) Do not transport or cause the transportation of species known to harbor insect or disease nests outside zones of infestation or current quarantine zones, as identified by the Department of Food and Agriculture or the Department of Forestry and Fire Protection, unless approved by the Department of Food and Agriculture and the Department of Forestry and Fire Protection.

**Assembly Bill 995 (Wright, Statutes of 2000, Chapter 1051) and Senate Bill 1194 (Sher, Statutes of 2000, Chapter 1050)**

**Public Utilities Code Section 399.6**

399.6. (a) In order to optimize public investment and ensure that the most cost-effective and efficient investments in renewable resources are vigorously pursued, the Energy Commission shall create an investment plan as set forth in paragraphs (1) to (3), inclusive, to govern the allocation of funds provided pursuant to this article. The Energy Commission's long-term goal shall be a fully competitive and self-sustaining California renewable energy supply. The investment plan shall be in accordance with all of the following:

(1) The investment plan's objective shall be to increase, in the near term, the quantity of California's electricity generated by in-state renewable energy resources, while protecting system reliability, fostering resource diversity, and obtaining the greatest environmental benefits for California residents.

(2) An additional objective of the plan shall be to identify and support emerging renewable energy technologies that have the greatest near-term commercial promise and that merit targeted assistance.

(3) The investment plan shall contain specific numerical targets, reflecting the projected impact of the plan, for both of the following:

(A) Increased quantity of California electrical generation produced from emerging technologies and from overall renewable resources.

(B) Increased supply of renewable generation available from facilities other than those selling to investor-owned utilities under contracts entered into prior to 1996 under the federal Public Utilities Regulatory Policies Act of 1978 (P.L. 95-617).

(b) The Energy Commission shall, on an annual basis, evaluate progress on meeting the targets set forth in subparagraphs (A) and (B) of paragraph (3) of subdivision (a), or any substitute provisions adopted by the Legislature upon review of the investment plan, and assess the impact of the investment plan on reducing the cost to Californians of renewable energy generation.

(c) In preparing these investment plans, the Energy Commission shall recommend allocations among all of the following:

(1) (A) Except as provided in subparagraph (B), production incentives for new renewable energy, including repowered or refurbished renewable energy.

(B) Allocations may not be made for renewable energy that is generated by a project that remains under a power purchase contract with an electrical corporation originally entered into prior to September 24, 1996, whether amended or restated thereafter.

(C) Notwithstanding subparagraph (B), production incentives for incremental new, repowered or refurbished renewable energy from existing projects under a power purchase contract with an electrical corporation originally entered into prior to September 24, 1996, whether amended or restated thereafter, may be allowed in any month, if all of the following occur:

(i) The project's power purchase contract provides that all energy delivered and sold under the contract is paid at a price that does not exceed commission approved short-run avoided cost of energy.

(ii) Either of the following:

(I) The power purchase contract is amended to provide that the kilowatthours used to determine the capacity payment in any time-of-delivery period in any month under the contract shall be equal to the actual kilowatthour production, but no greater than the five-year average of the kilowatthours delivered for the corresponding time-of-delivery period and month, in the years 1994 to 1998, inclusive.

(II) If a project's installed capacity as of December 31, 1998, is less than 75 percent of the nameplate capacity as stated in the power purchase contract, the power purchase contract is

amended to provide that the kilowatthours used to determine the capacity payment in any time-of-delivery period in any month under the contract shall be equal to the actual kilowatthour production, but no greater than the product of the five-year average of the kilowatthours delivered for the corresponding time-of-delivery period and month, in the years 1994 to 1998, inclusive, and the ratio of installed capacity as of December 31 of the previous year, but not to exceed contract nameplate capacity, to the installed capacity as of December 31, 1998.

(iii) The production incentive is payable only with respect to the kilowatthours delivered in a particular month that exceeds the corresponding five-year average calculated pursuant to clause (ii).

(2) Rebates, buydowns, or equivalent incentives for emerging renewable technologies.

(3) Customer credits for renewables not under contract with a utility.

(4) Customer education.

(5) Incentives for reducing fuel costs that are confirmed to the satisfaction of the Energy Commission at solid fuel biomass energy facilities in order to provide demonstrable environmental and public benefits, including but not limited to, air quality.

(6) Solar thermal generating resources that enhance the environmental value or reliability of the electricity system and that require financial assistance to remain economically viable, as determined by the Energy Commission. The Energy Commission may require financial disclosure from applicants for purposes of this paragraph.

(7) Specified fuel cell technologies, if the Energy Commission makes all of the following findings:

(A) The specified technologies have similar or better air pollutant characteristics than renewable technologies in the investment plan.

(B) The specified technologies require financial assistance to become commercially viable by reference to wholesale generation prices.

(C) The specified technologies could contribute significantly to the infrastructure development or other innovation required to meet the long-term objective of a self-sustaining, competitive supply of renewable energy.

(8) Existing wind-generating resources, if the Energy Commission finds that the existing wind-generating resources are a cost-effective source of reliability and environmental benefits compared with other eligible sources, and that the existing wind-generating resources require financial assistance to remain economically viable, as determined by the Energy Commission. The Energy Commission may require financial disclosure from applicants for the purposes of this paragraph.

(d) Commencing on January 1, 2002, public entities are not eligible to receive customer credits for renewables.

(e) Notwithstanding any other provision of law, moneys collected for renewable energy pursuant to this article shall be transferred to the Renewable Resource Trust Fund of the Energy Commission, to be held until further action by the Legislature. The Energy Commission shall prepare and submit to the Legislature, on or before March 31, 2001, an initial investment plan for these moneys, addressing the application of moneys collected between January 1, 2002, and January 1, 2007. The initial investment plan shall also include an evaluation of and report to the Legislature regarding the appropriateness and structure of a mandatory state purchase of renewable energy. On or before March 31, 2006, the Energy Commission shall prepare an investment plan proposing the application of moneys collected between January 1, 2007, and January 1, 2012. No moneys may be expended in the years covered by these plans without further legislative action.

## **Senate Bill 1305 (Sher, Statutes of 1997, Chapter 796)**

### **Public Utilities Code**

#### **Article 14. Disclosure of Sources of Electrical Generation**

398.1. (a) The Legislature finds and declares that there is a need for reliable, accurate, and timely information regarding fuel sources for electric generation offered for retail sale in California.

(b) The purpose of this article is to establish a program under which entities offering electric services in California disclose accurate, reliable, and simple to understand information on the sources of energy that are used to provide electric services.

398.2. The definitions set forth in this section shall govern the construction of this article.

(a) "System operator" means the Independent System Operator with responsibility for the efficient use and reliable operation of the transmission grid, as provided by Section 345, or a local publicly owned electric utility that does not utilize the Independent System Operator.

(b) "Specific purchases" means electricity transactions which are traceable to specific generation sources by any auditable contract trail or equivalent, such as a tradable commodity system, that provides commercial verification that the electricity source claimed has been sold once and only once to a retail consumer. Retail suppliers may rely on annual data to meet this requirement, rather than hour-by-hour matching of loads and resources.

(c) "Net system power" means the mix of electricity fuel source types established by the California Energy Resources Conservation and Development Commission representing the sources of electricity consumed in California that are not disclosed as specific purchases pursuant to Section 398.4.

398.3. (a) Beginning January 1, 1998, or as soon as practicable thereafter, each generator that provides meter data to a system operator shall report to the system operator electricity generated in kilowatthours by hour by generator, the fuel type or fuel types and fuel consumption by fuel type by month on an historical recorded quarterly basis. Facilities using only one fuel type may satisfy this requirement by reporting fuel type only. With regard to any facility using more than one fuel type, reports shall reflect the fuel consumed as a percentage of electricity generation.

(b) The California Energy Resources Conservation and Development Commission shall have authorization to access the electricity generation data in kilowatthours by hour for each facility that provides meter data to the system operator, and the fuel type or fuel types.

(c) With regard to out-of-state generation, the California Energy Resources Conservation and Development Commission shall have authorization to access the electricity generation data in kilowatthours by hour at the point at which out-of-state generation is metered, to the extent the information has been submitted to a system operator.

(d) Trade secrets as defined in subdivision (d) of Section 3426.1 of the Civil Code contained in the information provided to the system operators pursuant to this section shall be treated as confidential. These data may be disclosed only by the system operators and only by authorization of the generator except that the California Energy Resources Conservation and Development Commission shall have authorization to access these data, shall consider all these data to be trade secrets, and shall only release these data in an aggregated form such that trade secrets cannot be discerned.

398.4. (a) Every retail supplier that makes an offering to sell electricity that is consumed in California shall disclose its electricity sources. A retail supplier that does not make any claims that identify its electricity sources as different than net system power may disclose net system power. Every retail supplier that makes an offering to sell electricity that is consumed in California and makes any claims that identify any of its electricity sources as different than net system power shall disclose these sources as specific purchases.

(b) The disclosures required by this section shall be made to potential end-use consumers in all product-specific written promotional materials that are distributed to consumers by either printed or electronic means, except that advertisements and notices in general circulation media shall not be subject to this requirement.

(c) The disclosures required by this section shall be made at least quarterly to end-use consumers of the offered electricity.

(d) The disclosures required by this section shall be made separately for each offering made by the retail supplier.

(e) On or before January 1, 1998, the California Energy Resources Conservation and Development Commission shall specify guidelines for the format and means for disclosure required by Section 398.3 and this section, based on the requirements of this article and subject to public hearing.

(f) The costs of making the disclosures required by this section shall be considered to be generation-related.

(g) The disclosures required by this section shall be expressed as a percentage of annual sales derived from each of the following categories, unless no specific purchases are disclosed, in which case only the first category shall be disclosed:

(1) Net system power.

(2) Specific purchases.

(h) (1) Each of the categories specified in subdivision (g) shall be additionally identified as a percentage of annual sales that is derived from each fuel type of the categories specified as follows:

(A) Coal.

(B) Large hydroelectric (greater than 30 megawatts).

(C) Natural gas.

(D) Nuclear.

(E) Other.

(F) Eligible renewables, which means renewable resource technologies defined as electricity produced from other than a conventional power source within the meaning of Section 2805, provided that a power source utilizing more than 25 percent fossil fuel may not be included, shall be additionally identified as a percentage of annual sales that is derived from each fuel type of the subcategories specified as follows:

(i) Biomass and waste.

(ii) Geothermal.

(iii) Small hydroelectric (less than or equal to 30 megawatts).

(iv) Solar.

(v) Wind.

(2) The category "Other" shall be used for fuel types other than those listed above that represent less than 2 percent of net system power. The California Energy Resources Conservation and Development Commission may specify additional categories or change these categories, consistent with the requirements of this article and subject to public hearing, if it determines that the changes will facilitate the disclosure objectives of this section.

(i) All electricity sources disclosed as specific purchases shall meet the requirements of subdivision (b) of Section 398.2.

(j) Specific purchases identified pursuant to this section shall be from sources connected to the Western Systems Coordinating Council interconnected grid.

(k) Net system power shall be disclosed for the most recent calendar year available. Disclosure of net system power shall be accompanied by this qualifying note: "The State of California determines this net system power mix annually; your actual electricity purchases may vary." The California Energy Resources Conservation and Development Commission may modify this note, consistent with the requirements of this article and subject to public hearing, if it determines that the changes will facilitate the disclosure objectives of this section.

(l) For each offering made by a retail supplier for which specific purchases are disclosed, the retail supplier shall disclose projected specific purchases for the current calendar year. Projected specific purchases need not be disclosed by numerical percentage at the subcategory level identified in subparagraph (F) of paragraph (1) of subdivision (h). On or before April 15, 1999, and annually thereafter, every retail supplier that discloses specific purchases shall also disclose to its customers, separately for each offering made by the retail supplier, its actual specific purchases for the previous calendar year consistent with information provided to the California Energy Resources Conservation and Development Commission pursuant to Section 398.5. Disclosure of projected specific purchases and actual specific purchases shall each be accompanied by statements identifying whether the data are projected or actual, as developed by the California Energy Resources Conservation and Development Commission, subject to public hearing.

(m) The provisions of this section shall not apply to generators providing electric service onsite, under an over-the-fence transaction as described in Section 218, or to an affiliate or affiliates, as defined in subdivision (a) of Section 372.

398.5. (a) Retail suppliers that disclose specific purchases pursuant to Section 398.4 shall report on March 1, 1999, and annually thereafter, to the California Energy Resources Conservation and Development Commission, for each electricity offering, for the previous calendar year each of the following:

(1) The kilowatthours purchased, by generator and fuel type during the previous calendar year, consistent with the meter data, including losses, reported to the system operator.

(2) For each electricity offering the kilowatthours sold at retail.

(3) For each electricity offering the disclosures made to consumers pursuant to Section 398.4.

(b) Information submitted to the California Energy Resources Conservation and Development Commission pursuant to this section that is a trade secret as defined in subdivision (d) of Section 3426.1 of the Civil Code shall not be released except in an aggregated form such that trade secrets cannot be discerned.

(c) On or before January 1, 1998, the California Energy Resources Conservation and Development Commission shall specify guidelines and standard formats, based on the requirements of this article and subject to public hearing, for the submittal of information pursuant to this article.

(d) In developing the rules and procedures specified in this section, the California Energy Resources Conservation and Development Commission shall seek to minimize the reporting burden and cost of reporting that it imposes on retail suppliers.

(e) On or before October 15, 1999, and annually thereafter, the California Energy Resources Conservation and Development Commission shall issue a report comparing information available pursuant to Section 398.3 with information submitted by retail suppliers pursuant to this section, and with information disclosed to consumers pursuant to Section 398.4. This report shall be forwarded to the California Public Utilities Commission.

(f) Beginning April 15, 1999, and annually thereafter, the California Energy Resources Conservation and Development Commission shall issue a report calculating net system power. The California Energy Resources Conservation and Development Commission will establish the generation mix for net generation imports delivered at interface points and metered by the system operators. The California Energy Resources Conservation and Development Commission shall issue an initial report calculating preliminary net system power for calendar year 1997 on or before January 1, 1998. This report shall be updated on or before October 15, 1998.

(g) The provisions of this section shall not apply to generators providing electric service on site, under an over-the-fence transaction as described in Section 218, or to an affiliate or affiliates, as defined in subdivision (a) of Section 372.



(h) The California Energy Resources Conservation and Development Commission may verify the veracity of environmental claims made by retail suppliers. In addition, the Energy Resources Conservation and Development Commission, in conjunction with the California Air Resources Board and affected air districts, shall issue a report to the Legislature by June 1, 1999, assessing the air emission effects of electric utility restructuring.

SEC. 4. No reimbursement is required by this act pursuant to Section 6 of Article XIII B of the California Constitution because the only costs that may be incurred by a local agency or school district will be incurred because this act creates a new crime or infraction, eliminates a crime or infraction, or changes the penalty for a crime or infraction, within the meaning of Section 17556 of the Government Code, or changes the definition of a crime within the meaning of Section 6 of Article XIII B of the California Constitution.

Notwithstanding Section 17580 of the Government Code, unless otherwise specified, the provisions of this act shall become operative on the same date that the act takes effect pursuant to the California Constitution.

## **Senate Bill 183 (Sher, Statutes of 2003, Chapter 666)**

### **Public Resources Code**

SECTION 1. Section 25401.6 of the Public Resources Code is amended to read:

25401.6. (a) In its administration of Section 25744, the commission shall establish a separate rebate for eligible distributed emerging technologies for affordable housing projects including, but not limited to, projects undertaken pursuant to Section 50052.5, 50053, or 50199.4 of the Health and Safety Code. In establishing the rebate, where the commission determines that the occupants of the housing shall have individual meters, the commission may adjust the amount of the rebate based on the capacity of the system, provided that a system may receive a rebate only up to 75 percent of the total installed costs. The commission may establish a reasonable limit on the total amount of funds dedicated for purposes of this section.

(b) It is the intent of the Legislature that this section fulfills the purpose of paragraph (5) of subdivision (b) of Section 25744.

SEC. 2. Chapter 8.6 (commencing with Section 25740) is added to Division 15 of the Public Resources Code, to read:

### **CHAPTER 8.6. RENEWABLE ENERGY RESOURCES PROGRAM**

25740. It is the intent of the Legislature in establishing this program, to increase the amount of renewable electricity generated per year, so that it equals at least 17 percent of the total electricity generated for consumption in California per year by 2006.

25741. As used in this chapter, the following terms have the following meaning:

(a) "In-state renewable electricity generation facility" means a facility that meets all of the following criteria:

(1) The facility uses biomass, solar thermal, photovoltaic, wind, geothermal, fuel cells using renewable fuels, small hydroelectric generation of 30 megawatts or less, digester gas, municipal solid waste conversion, landfill gas, ocean wave, ocean thermal, or tidal current, and any additions or enhancements to the facility using that technology.

(2) The facility is located in the state or near the border of the state with the first point of connection to the Western Electricity Coordinating Council (WECC) transmission system located within this state.

(3) For the purposes of this subdivision, "solid waste conversion" means a technology that uses a noncombustion thermal process to convert solid waste to a clean-burning fuel for the purpose of generating electricity, and that meets all of the following criteria:

(A) The technology does not use air or oxygen in the conversion process, except ambient air to maintain temperature control.

(B) The technology produces no discharges of air contaminants or emissions, including greenhouse gases as defined in Section 42801.1 of the Health and Safety Code.

(C) The technology produces no discharges to surface or groundwaters of the state.

(D) The technology produces no hazardous wastes.

(E) To the maximum extent feasible, the technology removes all recyclable materials and marketable green waste compostable materials from the solid waste stream prior to the conversion process and the owner or operator of the facility certifies that those materials will be recycled or composted.

(F) The facility at which the technology is used is in compliance with all applicable laws, regulations, and ordinances.

(G) The technology meets any other conditions established by the commission.

(H) The facility certifies that any local agency sending solid waste to the facility diverted at least 30 percent of all solid waste it collects through solid waste reduction, recycling, and composting. For purposes of this paragraph "local agency" means any city, county, or special district, or subdivision thereof, which is authorized to provide solid waste handling services.

(b) "Renewable energy public goods charge" means that portion of the nonbypassable system benefits charge authorized to be collected and to be transferred to the Renewable Resource Trust Fund pursuant to the Reliable Electric Service Investments Act (Article 15 (commencing with Section 399) of Chapter 2.3 of Part 1 of Division 1 of the Public Utilities Code).

(c) "Report" means the report entitled "Investing in Renewable Electricity Generation in California" (June 2001, Publication Number P500-00-022) submitted to the Governor and the Legislature by the commission.

25742. (a) Twenty percent of the funds collected pursuant to the renewable energy public goods charge shall be used for programs that are designed to improve the competitiveness of existing in-state renewable electricity generation facilities, and to secure for the state the environmental, economic, and reliability benefits that continued operation of those facilities will provide. Eligibility for incentives under this section shall be limited to those technologies found eligible for funds by the commission pursuant to paragraphs (5), (6), and (8) of subdivision (c) of Section 399.6 of the Public Utilities Code.

(b) Any funds used to support in-state renewable electricity generation facilities pursuant to this section shall be expended in accordance with the provisions of the report, subject to all of the following requirements:

(1) Of the funding for existing renewable electricity generation facilities available pursuant to this section, 75 percent shall be used to fund first tier technologies, including biomass and solar electric technologies and 25 percent shall be used to fund second tier wind technologies.

(2) The commission shall reexamine the tier structure as proposed in the report and adjust the structure to reflect market and contractual conditions. The commission shall also consider inflation when adjusting the structure.

(3) The commission shall establish a cents per kilowatthour production incentive, not to exceed the payment caps per kilowatthour established in the report, as those payment caps are revised in guidelines adopted by the commission, representing the difference between target prices and the price paid for electricity, if sufficient funds are available. If there are insufficient funds in any payment period to pay either the difference between the target and price paid for electricity or the payment caps, production incentives shall be based on the amount determined by dividing available funds by eligible generation. The price paid for electricity shall be determined by the commission based on the energy prices paid to nonutility power generators as authorized by the Public Utilities Commission, or on otherwise available measures of price. For the first tier technologies, the commission shall establish a time-differentiated incentive structure that encourages plants to run the maximum feasible amount of time and that provides a higher incentive when the plants are receiving the lowest price.

(4) Facilities that are eligible to receive funding pursuant to this section shall be registered in accordance with criteria developed by the commission and those facilities may not receive payments for any electricity produced that has any of the following characteristics:

(A) Is sold at monthly average rates equal to or greater than the applicable target price, as determined by the commission.

(B) Is that portion of electricity generation attributable to the use of qualified agricultural biomass fuel, for a facility that is receiving fuel-based incentives through the Agricultural Biomass-to-Energy Incentive Grant Program established pursuant to Part 3 (commencing with Section 1101) of Division 1 of the Food and Agricultural Code. Notwithstanding subdivision (f) of Section 1104 of the Food and Agricultural Code, facilities that receive funding from the

Agricultural Biomass-to-Energy Incentive Grant Program are eligible to receive funding pursuant to this section.

(C) Is used onsite or is sold to customers in a manner that excludes competitive transition charge payments, or is otherwise excluded from competitive transition charge payments.

25743. (a) Fifty-one and one-half percent of the money collected pursuant to the renewable energy public goods charge, shall be used for programs designed to foster the development of new in-state renewable electricity generation facilities, and to secure for the state the environmental, economic, and reliability benefits that operation of those facilities will provide.

(b) Any funds used for new in-state renewable electricity generation facilities pursuant to this section shall be expended in accordance with the report, subject to all of the following requirements:

(1) In order to cover the above market costs of renewable resources as approved by the Public Utilities Commission and selected by retail sellers to fulfill their obligations under Article 16 (commencing with Section 399.11) of Chapter 2.3 of Part 1 of Division 1 of the Public Utilities Code, the commission shall award funds in the form of supplemental energy payments, subject to the following criteria:

(A) The commission may establish caps on supplemental energy payments. The caps shall be designed to provide for a viable energy market capable of achieving the goals of Article 16 (commencing with Section 399.11) of Chapter 2.3 of Part 1 of the Public Utilities Code. The commission may waive application of the caps to accommodate a facility, if it is demonstrated to the satisfaction of the commission, that operation of the facility would provide substantial economic and environmental benefits to end-use customers subject to the funding requirements of the renewable energy public goods charge.

(B) Supplemental energy payments shall be awarded only to facilities that are eligible for funding under this subdivision.

(C) Supplemental energy payments awarded to facilities selected by an electrical corporation pursuant to Article 16 (commencing with Section 399.11) of Chapter 2.3 of Part 1 of Division 1 of the Public Utilities Code shall be paid for the lesser of 10 years, or the duration of the contract with the electrical corporation.

(D) The commission shall reduce or terminate supplemental energy payments for projects that fail either to commence and maintain operations consistent with the contractual obligations to an electrical corporation, or that fail to meet eligibility requirements.

(E) Funds shall be managed in an equitable manner in order for retail sellers to meet their obligation under Article 16 (commencing with Section 399.11) of Chapter 2.3 of Part 1 of Division 1 of the Public Utilities Code.

(2) The commission may determine as part of a solicitation, that a facility that does not meet the definition of an "in-state renewable electricity generation technology" facility solely because it is located outside the state, is eligible for funding under this subdivision if it meets all of the following requirements:

(A) It is located so that it is or will be connected to the Western Electricity Coordinating Council (WECC) transmission system.

(B) It is developed with guaranteed contracts to sell its generation to end-use customers subject to the funding requirements of Section 381, or to marketers that provide this guarantee for resale of the generation, for a period of time at least equal to the amount of time it receives incentive payments under this subdivision.

(C) It will not cause or contribute to any violation of a California environmental quality standard or requirement.

(D) If the facility is outside of the United States, it is developed and operated in a manner that is as protective of the environment as a similar facility located in the state.

(E) It meets any other condition established by the commission.

(3) Facilities that are eligible to receive funding pursuant to this subdivision shall be registered in accordance with criteria developed by the commission and those facilities may not receive payments for any electricity produced that has any of the following characteristics:

(A) Is sold under an existing long-term contract with an existing in-state electrical corporation if the contract includes fixed energy or capacity payments, except for that electricity that satisfies subparagraph (C) of paragraph (1) of subdivision (c) of Section 399.6 of the Public Utilities Code.

(B) Is used onsite or is sold to customers in a manner that excludes competitive transition charge payments, or is otherwise excluded from competitive transition charge payments.

(C) Is produced by a facility that is owned by an electrical corporation or a local publicly owned electric utility as defined in subdivision (d) of Section 9604 of the Public Utilities Code.

(D) Is a hydroelectric generation project that will require a new or increased appropriation of water under Part 2 (commencing with Section 1200) of Division 2 of the Water Code.

(E) Is a solid waste conversion facility, unless the facility meets the criteria established in paragraph (3) of subdivision (a) of Section 25741 and the facility certifies that any local agency sending solid waste to the facility is in compliance with Division 30 (commencing with Section 40000), has reduced, recycled, or composted solid waste to the maximum extent feasible, and shall have been found by the California Integrated Waste Management Board to have diverted at least 30 percent of all solid waste through source reduction, recycling, and composting.

(4) Eligibility to compete for funds or to receive funds shall be contingent upon having to sell the output of the renewable electricity generation facility to customers subject to the funding requirements of the renewable energy public goods charge.

(5) The commission may require applicants competing for funding to post a forfeitable bid bond or other financial guaranty as an assurance of the applicant's intent to move forward expeditiously with the project proposed. The amount of any bid bond or financial guaranty may not exceed 10 percent of the total amount of the funding requested by the applicant.

(6) In awarding funding, the commission may provide preference to projects that provide tangible demonstrable benefits to communities with a plurality of minority or low-income populations.

(c) Repowered existing facilities shall be eligible for funding under this subdivision if the capital investment to repower the existing facility equals at least 80 percent of the value of the repowered facility.

(d) Facilities engaging in the direct combustion of municipal solid waste or tires are not eligible for funding under this subdivision.

(e) Production incentives awarded under this subdivision prior to January 1, 2002, shall commence on the date that a project begins electricity production, provided that the project was operational prior to January 1, 2002, unless the commission finds that the project will not be operational prior to January 1, 2002, due to circumstances beyond the control of the developer. Upon making a finding that the project will not be operational due to circumstances beyond the control of the developer, the commission shall pay production incentives over a five-year period, commencing on the date of operation, provided that the date that a project begins electricity production may not extend beyond January 1, 2007.

(f) Facilities generating electricity from biomass energy shall be considered an in-state renewable electricity generation technology facility to the extent that they report to the commission the types and quantities of biomass fuels used and certify to the satisfaction of the commission that fuel utilization is limited to the following:

(1) Agricultural crops and agricultural wastes and residues.

(2) Solid waste materials such as waste pallets, crates, dunnage, manufacturing, and construction wood wastes, landscape or right-of-way tree trimmings, mill residues that are directly the result of the milling of lumber, and rangeland maintenance residues.

(3) Wood and wood wastes that meet all of the following requirements:

(A) Have been harvested pursuant to an approved timber harvest plan prepared in accordance with the Z'berg-Nejedly Forest Practice Act of 1973 (Chapter 8 (commencing with Sec. 4511) of Part 2 of Division 4).

(B) Have been harvested for the purpose of forest fire fuel reduction or forest stand improvement.

(C) Do not transport or cause the transportation of species known to harbor insect or disease nests outside zones of infestation or current quarantine zones, as identified by the Department of Food and Agriculture or the Department of Forestry and Fire Protection, unless approved by the Department of Food and Agriculture and the Department of Forestry and Fire Protection.

25744. (a) Seventeen and one-half percent of the money collected pursuant to the renewable energy public goods charge shall be used for a multiyear, consumer-based program to foster the development of emerging renewable technologies in distributed generation applications.

(b) Any funds used for emerging technologies pursuant to this section shall be expended in accordance with the report, subject to all of the following requirements:

(1) Funding for emerging technologies shall be provided through a competitive, market-based process that shall be in place for a period of not less than five years, and shall be structured so as to allow eligible emerging technology manufacturers and suppliers to anticipate and plan for increased sale and installation volumes over the life of the program.

(2) The program shall provide monetary rebates, buydowns, or equivalent incentives, subject to subparagraph (C), to purchasers, lessees, lessors, or sellers of eligible electricity generating systems. Incentives shall benefit the end-use consumer of renewable generation by directly and exclusively reducing the purchase or lease cost of the eligible system, or the cost of electricity produced by the eligible system. Incentives shall be issued on the basis of the rated electrical generating capacity of the system measured in watts, or the amount of electricity production of the system, measured in kilowatthours. Incentives shall be limited to a maximum percentage of the system price, as determined by the commission.

(3) Eligible distributed emerging technologies are photovoltaic, solar thermal electric, fuel cell technologies that utilize renewable fuels, and wind turbines of not more than 50 kilowatts rated electrical generating capacity per customer site, and other distributed renewable emerging technologies that meet the emerging technology eligibility criteria established by the commission. Eligible electricity generating systems are intended primarily to offset part or all of the consumer's own electricity demand, and shall not be owned by local publicly owned electric utilities, nor be located at a customer site that is not receiving distribution service from an electrical corporation that is subject to the renewable energy public goods charge and contributing funds to support programs under this chapter. All eligible electricity generating system components shall be new and unused, shall not have been previously placed in service in any other location or for any other application, and shall have a warranty of not less than five years to protect against defects and undue degradation of electrical generation output. Systems and their fuel resources shall be located on the same premises of the end-use consumer where the consumer's own electricity demand is located, and all eligible electricity generating systems shall be connected to the utility grid in California. The commission may require eligible electricity generating systems to have meters in place to monitor and measure a system's performance and generation. Only systems that will be operated in compliance with applicable law and the rules of the Public Utilities Commission shall be eligible for funding.

(4) The commission shall limit the amount of funds available for any system or project of multiple systems and reduce the level of funding for any system or project of multiple systems that has received, or may be eligible to receive, any government or utility funds, incentives, or credit.

(5) In awarding funding, the commission may provide preference to systems that provide tangible demonstrable benefits to communities with a plurality of minority or low-income populations.

(6) In awarding funding, the commission shall develop and implement eligibility criteria and a system that provides preference to systems based upon system performance, taking into account factors, including, but not limited to, shading, insulation levels, and installation orientation.

(7) At least once annually, the commission shall publish and make available to the public the balance of funds available for emerging renewable energy resources for rebates, buydowns, and other incentives for the purchase of these resources.

25745. (a) Ten percent of the money collected pursuant to the renewable energy public goods charge shall be used to provide customer credits to customers that entered into a direct transaction on or before September 20, 2001, for purchases of electricity produced by registered in-state renewable electricity generating facilities.

(b) Any funds used for customer credits pursuant to this section shall be expended, as provided in the report, subject to all of the following requirements:

(1) Customer credits shall be awarded to California retail customers located in the service territory of an electrical corporation that is subject to the renewable energy public goods charge that is contributing funds to support programs under this chapter, and that is purchasing qualifying electricity from renewable electricity generating facilities, through transactions traceable to specific generation sources by any auditable contract trail or equivalent that provides commercial verification that the electricity from the claimed renewable electricity generating facilities has been sold once and only once to a retail customer.

(2) Credits awarded pursuant to this paragraph may be paid directly to electric service providers, energy marketers, aggregators, or generators if those persons or entities account for the credits on the recipient customer's bills. Credits may not exceed one and one-half cents (\$0.015) per kilowatthour. Credits awarded to members of the combined class of customers, other than residential and small commercial customers, may not exceed one thousand dollars (\$1,000) per customer per calendar year. In no event may more than 20 percent of the total customer incentive funds be awarded to members of the combined class of customers other than residential and small commercial customers.

(3) The commission shall develop criteria and procedures for the identification of energy purchasers and providers that are eligible to receive funds pursuant to this paragraph through a process consistent with this paragraph. These criteria and procedures shall apply only to funding eligibility and may not extend to other renewable marketing claims.

(4) Customer credits may not be awarded for the purchase of electricity that is used to meet the obligations of a renewable portfolio standard.

(5) The Public Utilities Commission shall notify the commission in writing within 10 days of revoking or suspending the registration of any electric service provider pursuant to paragraph (4) of subdivision (b) of Section 394.25 of the Public Utilities Code.

25746. One percent of the money collected pursuant to the renewable energy public goods charge shall be used in accordance with the report to promote renewable energy and disseminate information on renewable energy technologies, including emerging renewable technologies, and to help develop a consumer market for renewable energy and for small-scale emerging renewable energy technologies.

25747. (a) The commission shall adopt guidelines governing the funding programs authorized under this chapter, at a publicly noticed meeting offering all interested parties an opportunity to comment. Substantive changes to the guidelines may not be adopted without at least 10 days' written notice to the public. The public notice of meetings required by this subdivision may not be less than 30 days. Notwithstanding any other provision of law, any guidelines adopted pursuant to this chapter shall be exempt from the requirements of Chapter 3.5 (commencing with Section 11340) of Part 1 of Division 3 of Title 2 of the Government Code.

The Legislature declares that the changes made to this subdivision by the act amending this section during the 2002 portion of the 2001-02 Regular Session are declaratory of, and not a change in existing law.

(b) Funds to further the purposes of this chapter may be committed for multiple years.

(c) Awards made pursuant to this chapter are grants, subject to appeal to the commission upon a showing that factors other than those described in the guidelines adopted by the commission were applied in making the awards and payments. Any actions taken by an applicant to apply for, or become or remain eligible and registered to receive, payments or awards, including satisfying conditions specified by the commission, shall not constitute the rendering of goods, services, or a direct benefit to the commission.

25748. The commission shall report to the Legislature on or before May 31, 2000, and on or before May 31 of every second year thereafter, regarding the results of the mechanisms funded pursuant to this chapter. Reports prepared pursuant to this section shall include a description of the allocation of funds among existing, new and emerging technologies; the allocation of funds among programs, including consumer-side incentives; and the need for the reallocation of money among those technologies. The report shall identify the types and quantities of biomass fuels used by facilities receiving funds pursuant to Section 25743 and their impacts on improving air quality. The reports shall discuss the progress being made toward achieving the 17-percent target provided in Section 25740 by each funding category authorized pursuant to this chapter. The reports shall also address the allocation of funds from interest on the accounts described in this chapter, and money in the accounts described in subdivision (b) of Section 25751. Money may be reallocated without further legislative action among existing, new, and emerging technologies and consumer-side programs in a manner consistent with the report and with the latest report provided to the Legislature pursuant to this section, except that reallocations may not reduce the allocation established in Section 25743 nor increase the allocation established in Section 25742.

25749. The commission shall, by December 1, 2003, prepare and submit to the Legislature a comprehensive renewable electricity generation resource plan that describes the renewable resource potential available in California, and recommendations for a plan for development to achieve the target of increasing the amount of electricity generated from renewable sources per year, so that it equals 17 percent of the total electricity generated for consumption in California by 2006. The commission shall consult with the Public Utilities Commission, electrical corporations, and the Independent System Operator, in the development and preparation of the plan.

25750. The commission shall participate in proceedings at the Public Utilities Commission that relate to or affect efforts to stimulate the development of electricity generated from renewable sources, in order to obtain coordination of the state's efforts to achieve the target of increasing the amount of electricity generated from renewable sources per year, so that it equals 17 percent of the total electricity generated for consumption in California by 2006.

25751. (a) The Renewable Resource Trust Fund is hereby created in the State Treasury.

(b) The following accounts are hereby established within the Renewable Resource Trust Fund:

- (1) The Existing Renewable Resources Account.
- (2) New Renewable Resources Account.
- (3) Emerging Renewable Resources Account.
- (4) Customer-Credit Renewable Resource Purchases Account.
- (5) Renewable Resources Consumer Education Account.

(c) The money in the fund may be expended for the state's administration of this article only upon appropriation by the Legislature in the annual Budget Act.

(d) Notwithstanding Section 383, that portion of revenues collected by electrical corporations for the benefit of in-state operation and development of existing and new and emerging renewable resource technologies, pursuant to Section 399.8 of the Public Utilities



Code, shall be transmitted to the commission at least quarterly for deposit in the Renewable Resource Trust Fund pursuant to Section 399.6 of the Public Utilities Code. After setting aside in the fund money that may be needed for expenditures authorized by the annual Budget Act in accordance with subdivision (c), the Treasurer shall immediately deposit money received pursuant to this section into the accounts created pursuant to subdivision (b) in proportions designated by the commission for the current calendar year. Notwithstanding Section 13340 of the Government Code, the money in the fund and the accounts within the fund are hereby continuously appropriated to the commission without regard to fiscal year for the purposes enumerated in this chapter.

(e) Upon notification by the commission, the Controller shall pay all awards of the money in the accounts created pursuant to subdivision (b) for purposes enumerated in this chapter. The eligibility of each award shall be determined solely by the commission based on the procedures it adopts under this chapter. Based on the eligibility of each award, the commission shall also establish the need for a multiyear commitment to any particular award and so advise the Department of Finance. Eligible awards submitted by the commission to the Controller shall be accompanied by information specifying the account from which payment should be made and the amount of each payment; a summary description of how payment of the award furthers the purposes enumerated in this chapter; and an accounting of future costs associated with any award or group of awards known to the commission to represent a portion of a multiyear funding commitment.

(f) The commission may transfer funds between accounts for cashflow purposes, provided that the balance due each account is restored and the transfer does not adversely affect any of the accounts. The commission shall examine the cashflow in the respective accounts on an annual basis, and shall annually prepare and submit to the Legislature a report that describes the status of account transfers and repayments.

(g) The commission shall, on a quarterly basis, report to the Legislature on the implementation of this article. Those quarterly reports shall be submitted to the Legislature not more than 30 days after the close of each quarter and shall include information describing the awards submitted to the Controller for payment pursuant to this article, the cumulative commitment of claims by account, the relative demand for funds by account, a forecast of future awards, and other matters the commission determines may be of importance to the Legislature.

(h) The Department of Finance, commencing March 1, 1999, shall conduct an independent audit of the Renewable Resource Trust Fund and its related accounts annually, and provide an audit report to the Legislature not later than March 1 of each year for which this article is operative. The Department of Finance's report shall include information regarding revenues, payment of awards, reserves held for future commitments, unencumbered cash balances, and other matters that the Director of Finance determines may be of importance to the Legislature.

SEC. 3. Section 383.5 of the Public Utilities Code is repealed.

SEC. 4. Section 383.6 of the Public Utilities Code is amended to read:

383.6. The commission shall, by December 1, 2003, prepare and submit to the Legislature, a comprehensive transmission plan for renewable electricity generation facilities, to provide for the rational, orderly, cost-effective expansion of transmission facilities that may be necessary to facilitate the development of renewable electricity generation facilities identified in the renewable electricity generation resource plan prepared pursuant to Section 25749 of the Public Resources Code. The commission shall consult with the State Energy Resources Conservation and Development Commission, the Independent System Operator, and electrical corporations in the development of and preparation of the plan.

SEC. 5. Section 383.7 of the Public Utilities Code is repealed.

SEC. 6. Section 394.25 of the Public Utilities Code is amended to read:

394.25. (a) The commission may enforce the provisions of Sections 2102, 2103, 2104, 2105, 2107, 2108, and 2114 against electric service providers as if those electric service providers were public utilities as defined in these code sections. Notwithstanding the above, nothing in this section grants the commission jurisdiction to regulate electric service providers other than as specifically set forth in this part. Electric service providers shall continue to be subject to the provisions of Sections 2111 and 2112. Upon a finding by the commission's executive director that there is evidence to support a finding that the electric service provider has committed an act constituting grounds for suspension or revocation of registration as set forth in subdivision (b) of Section 394.25, the commission shall notify the electric service provider in writing and notice an expedited hearing on the suspension or revocation of the electric service provider's registration to be held within 30 days of the notification to the electric service provider of the executive director's finding of evidence to support suspension or revocation of registration. The commission shall, within 45 days after holding the hearing, issue a decision on the suspension or revocation of registration, which shall be based on findings of fact and conclusions of law based on the evidence presented at the hearing. The decision shall include the findings of fact and the conclusions of law relied upon.

(b) An electric service provider may have its registration suspended or revoked, immediately or prospectively, in whole or in part, for any of the following acts:

(1) Making material misrepresentations in the course of soliciting customers, entering into service agreements with those customers, or administering those service agreements.

(2) Dishonesty, fraud, or deceit with the intent to substantially benefit the electric service provider or its employees, agents, or representatives, or to disadvantage retail electric customers.

(3) Where the commission finds that there is evidence that the electric service provider is not financially or operationally capable of providing the offered electric service.

(4) The misrepresentation of a material fact by an applicant in obtaining a registration pursuant to Section 394.

(c) Pursuant to its authority to revoke or suspend registration, the commission may suspend a registration for a specified period or revoke the registration, or in lieu of suspension or revocation, impose a moratorium on adding or soliciting additional customers. Any suspension or revocation of a registration shall require the electric service provider to cease serving customers within the boundaries of investor-owned electric corporations, and the affected customers shall be served by the electrical corporation until the time when they may select service from another service provider. Customers shall not be liable for the payment of any early termination fees or other penalties to any electric service provider under the service agreement if the serving electric service provider's registration is suspended or revoked.

(d) The commission shall require any electric service provider whose registration is revoked pursuant to paragraph (4) of subdivision (b) to refund all of the customer credit funds that the electric service provider received from the State Energy Resources Conservation and Development Commission pursuant to subdivision (a) of Section 25744 of the Public Resources Code. The repayment of these funds shall be in addition to all other penalties and fines appropriately assessed the electric service provider for committing those acts under other provisions of law. All customer credit funds refunded under this subdivision shall be deposited in the Renewable Resource Trust Fund for redistribution by the State Energy Resources Conservation and Development Commission pursuant to Chapter 8.6 (commencing with Section 25740) of Division 15 of the Public Resources Code. This subdivision may not be construed to apply retroactively.

(e) If a customer of an electric service provider or a community choice aggregator is involuntarily returned to service provided by an electrical corporation, any reentry fee imposed on that customer that the commission deems is necessary to avoid imposing costs on other customers of the electric corporation shall be the obligation of the electric service provider or a

community choice aggregator, except in the case of a customer returned due to default in payment or other contractual obligations or because the customer's contract has expired. As a condition of its registration, an electric service provider or a community choice aggregator shall post a bond or demonstrate insurance sufficient to cover those reentry fees. In the event that an electric service provider becomes insolvent and is unable to discharge its obligation to pay reentry fees, the fees shall be allocated to the returning customers.

SEC. 7. Section 399.6 of the Public Utilities Code, as added by Section 4 of Chapter 1050 of the Statutes of 2000, is repealed.

SEC. 8. Section 399.8 of the Public Utilities Code, as amended by Section 1 of Chapter 770 of the Statutes of 2001, is repealed.

SEC. 9. Section 399.8 of the Public Utilities Code, as amended by Section 2 of Chapter 770 of the Statutes of 2001, is amended to read:

399.8. (a) In order to ensure that the citizens of this state continue to receive safe, reliable, affordable, and environmentally sustainable electric service, it is the policy of this state and the intent of the Legislature that prudent investments in energy efficiency, renewable energy, and research, development and demonstration shall continue to be made.

(b) (1) Every customer of an electrical corporation, shall pay a nonbypassable system benefits charge authorized pursuant to this article. The system benefits charge shall fund energy efficiency, renewable energy, and research, development and demonstration.

(2) Local publicly owned electric utilities shall continue to collect and administer system benefits charges pursuant to Section 385.

(c) (1) The commission shall require each electrical corporation to identify a separate rate component to collect revenues to fund energy efficiency, renewable energy, and research, development and demonstration programs authorized pursuant to this section beginning January 1, 2002, through January 1, 2012. The rate component shall be a nonbypassable element of the local distribution service and collected on the basis of usage.

(2) This rate component may not exceed, for any tariff schedule, the level of the rate component that was used to recover funds authorized pursuant to Section 381 on January 1, 2000. If the amounts specified in paragraph (1) of subdivision (d) are not recovered fully in any year, the commission shall reset the rate component to restore the unrecovered balance, provided that the rate component may not exceed, for any tariff schedule, the level of the rate component that was used to recover funds authorized pursuant to Section 381 on January 1, 2000. Pending restoration, any annual shortfalls shall be allocated pro rata among the three funding categories in the proportions established in paragraph (1) of subdivision (d).

(d) The commission shall order San Diego Gas and Electric Company, Southern California Edison Company, and Pacific Gas and Electric Company to collect these funds commencing on January 1, 2002, as follows:

(1) Two hundred twenty-eight million dollars (\$228,000,000) per year in total for energy efficiency and conservation activities, one hundred thirty-five million dollars (\$135,000,000) in total per year for renewable energy, and sixty-two million five hundred thousand dollars (\$62,500,000) in total per year for research, development and demonstration. The funds for energy efficiency and conservation activities shall continue to be allocated in proportions established for the year 2000 as set forth in paragraph (1) of subdivision (c) of Section 381.

(2) The amounts shall be adjusted annually at a rate equal to the lesser of the annual growth in electric commodity sales or inflation, as defined by the gross domestic product deflator. (e) The commission and the Energy Commission shall retain and continue their oversight responsibilities as set forth in Sections 381 and 383, and Chapter 7.1 (commencing with Section 25620) and Chapter 8.6 (commencing with Section 25740) of Division 15 of the Public Resources Code.

(f) (1) On or before January 1, 2004, the Governor shall appoint an independent review panel including, but not limited to, members with expertise on the energy service needs of large and small electricity consumers, system reliability issues, and energy-related public policy. On or before January 1, 2005, the panel shall prepare and submit to the Legislature and the Energy Commission a report evaluating the energy efficiency, renewable energy, and research, development and demonstration programs funded under this section. Reasonable costs associated with the review in each of the three program categories, including technical assistance, may be charged to the relevant program category under procedures to be developed by the commission for energy efficiency and by the Energy Commission for renewable energy and research development and demonstration.

(2) The report shall also assess all of the following:

(A) Whether ongoing programs are consistent with the statutory goals.

(B) Whether potential synergies among the program categories described in paragraph (1) that could provide enhanced public value have been identified and incorporated in the programs.

(C) If established targets for increased renewable generation are likely to be achieved.

(D) What changes should be made to result in a more efficient use of public resources.

(3) The report shall also compare the Energy Commission's programs with efforts undertaken by other states and assess, as an alternative, the relative costs and benefits of adopting a tradable minimum renewable energy requirement in California. The evaluation shall include recommendations intended to optimize renewable resource development at the least cost.

(4) For energy efficiency programs, the report shall include an evaluation of all of the following:

(A) The net benefits secured for residential customers, taking into account both public and private costs, including improvements in that customer group's ability to avoid or reduce consumption of relatively costly peak electricity.

(B) Whether the programs provide a balance of benefits to all sectors that contribute to the funding.

(C) The extent to which competition in energy markets including, but not limited to, load participation in ancillary services markets, and improvements in technology affect the continuing need for such programs.

(D) The status and growth of the private, competitive energy services industry that provides energy efficiency services and other energy products to customers.

(E) The commercial availability of any new technologies that reduce electricity demands during high-priced periods.

(F) Customers' willingness and ability to reduce consumption or adopt energy efficiency measures without program support.

(G) The extent to which the programs have delivered cost-effective energy efficiency not adequately provided by markets and as a result have reduced energy demand and consumption.

(H) The relative cost-effectiveness of program expenditures compared to other current or potential expenditures to enhance system reliability.

(5) The report shall include specific recommendations aimed at assisting the Legislature in determining whether to change or eliminate the collection of the system benefits charge on or after January 1, 2007.

(6) The panel may update and revise the report as needed.

(g) Promptly after receiving the panel's report, the commission shall convene a proceeding to address implementation of the panel's energy efficiency recommendations.

(h) An applicant for the Large Nonresidential Standard Performance Contract Program funded pursuant to paragraph (1) of subdivision (b) and an electrical corporation shall promptly

attempt to resolve disputes that arise related to the program's guidelines and parameters prior to entering into a program agreement. The applicant shall provide the electrical corporation with written notice of any dispute. Within 10 business days after receipt of the notice, the parties shall meet to resolve the dispute. If the dispute is not resolved within 10 business days after the date of the meeting, the electrical corporation shall notify the applicant of his or her right to file a complaint with the commission, which complaint shall describe the grounds for the complaint, injury, and relief sought. The commission shall issue its findings in response to a filed complaint within 30 business days of the date of receipt of the complaint. Prior to issuance of its findings, the commission shall provide a copy of the complaint to the electrical corporation, which shall provide a response to the complaint to the commission within five business days of the date of receipt. During the dispute period, the amount of estimated financial incentives shall be held in reserve until the dispute is resolved.

SEC. 10. Section 445 of the Public Utilities Code is repealed.

## **Senate Bill 67 (Bowen, Statutes of 2003, Chapter 731)**

THE PEOPLE OF THE STATE OF CALIFORNIA DO ENACT AS FOLLOWS:

SECTION 1. Section 399.14 of the Public Utilities Code is amended to read:

399.14. (a) The commission shall direct each electrical corporation to prepare renewable energy procurement plans as described in paragraph (3) to satisfy its obligations under the renewables portfolio standard. To the extent feasible, this procurement plan shall be proposed, reviewed, and adopted by the commission as part of, and pursuant to, a general procurement plan process. The commission shall require each electrical corporation to review and update its renewable energy procurement plan as it determines to be necessary.

(1) (A) The commission shall not require an electrical corporation to conduct procurement to fulfill the renewables portfolio standard until the commission determines either of the following:

(i) The electrical corporation has attained an investment grade credit rating as determined by at least two major rating agencies.

(ii) The electrical corporation is able to procure eligible renewable energy resources on reasonable terms, those resources can be financed if necessary, and the procurement will not impair the restoration of an electrical corporation's creditworthiness. This provision shall not apply before April 1, 2004, for any electrical corporation that on June 30, 2003, is in federal court under Chapter 11 of the federal bankruptcy law.

(B) Within 90 days of the commission's determination as provided in subparagraph (A), an electrical corporation shall conduct solicitations to implement a renewable energy procurement plan. The determination required by this paragraph shall apply only to the requirements established pursuant to this article. The requirements established for an electrical corporation pursuant to Section 454.5 shall be governed by that section.

(2) Not later than six months after the effective date of this section, the commission shall adopt, by rule, for all electrical corporations, all of the following:

(A) A process for determining market prices pursuant to subdivision (c) of Section 399.15. The commission shall make specific determinations of market prices after the closing date of a competitive solicitation conducted by an electrical corporation for eligible renewable energy resources. In order to ensure that the market price established by the commission pursuant to subdivision (c) of Section 399.15 does not influence the amount of a bid submitted through the competitive solicitation in a manner that would increase the amount ratepayers are obligated to pay for renewable energy, and in order to ensure that the bid price does not influence the establishment of the market price, the electrical corporation shall not transmit or share the results of any competitive solicitation for eligible renewable energy resources until the commission has established market prices pursuant to subdivision (c) of Section 399.15.

(B) A process that provides criteria for the rank ordering and selection of least-cost and best-fit renewable resources to comply with the annual California Renewables Portfolio Standard Program obligations on a total cost basis. This process shall consider estimates of indirect costs associated with needed transmission investments and ongoing utility expenses resulting from integrating and operating eligible renewable energy resources.

(C) Flexible rules for compliance including, but not limited to, permitting electrical corporations to apply excess procurement in one year to subsequent years or inadequate procurement in one year to no more than the following three years.

(D) Standard terms and conditions to be used by all electrical corporations in contracting for eligible renewable energy resources, including performance requirements for renewable generators.

(3) Consistent with the goal of procuring the least-cost and best-fit eligible renewable energy resources, the renewable energy procurement plan submitted by an electrical corporation shall include, but is not limited to, all of the following:

(A) An assessment of annual or multiyear portfolio supplies and demand to determine the optimal mix of renewable generation resources with deliverability characteristics that may include peaking, dispatchable, baseload, firm, and as-available capacity.

(B) Provisions for employing available compliance flexibility mechanisms established by the commission.

(C) A bid solicitation setting forth the need for renewable generation of each deliverability characteristic, required online dates, and locational preferences, if any.

(4) In soliciting and procuring eligible renewable energy resources, each electrical corporation shall offer contracts of no less than 10 years in duration, unless the commission approves of a contract of shorter duration.

(5) In soliciting and procuring eligible renewable energy resources, each electrical corporation may give preference to projects that provide tangible demonstrable benefits to communities with a plurality of minority or low-income populations.

(b) The commission shall review and accept, modify, or reject each electrical corporation's renewable procurement plan 90 days prior to the commencement of renewable procurement pursuant to this article by the electrical corporation.

(c) The commission shall review the results of a renewable energy resources solicitation submitted for approval by an electrical corporation and accept or reject proposed contracts with eligible renewable energy resources based on consistency with the approved renewable procurement plan. If the commission determines that the bid prices are elevated due to a lack of effective competition amongst the bidders, the commission shall direct the electrical corporation to renegotiate such contracts or conduct a new solicitation.

(d) If an electrical corporation fails to comply with a commission order adopting a renewable procurement plan, the commission shall exercise its authority pursuant to Section 2113 to require compliance.

(e) Upon application by an electrical corporation, the commission may authorize another entity to enter into contracts on behalf of customers of the electrical corporation for deliveries of eligible renewable energy resources to satisfy the annual portfolio standard obligations, subject to similar terms and conditions applicable to an electrical corporation. The commission shall allow the procurement entity to recover reasonable costs through retail rates subject to review and approval.

(f) Procurement and administrative costs associated with long-term contracts entered into by an electrical corporation for eligible renewable energy resources pursuant to this article, at or below the market price determined by the commission pursuant to subdivision (c) of Section 399.15, shall be deemed reasonable per se, and shall be recoverable in rates.

(g) For purposes of this article, "procure" means that a utility may acquire the renewable output of electric generation facilities that it owns or for which it has contracted. Nothing in this article is intended to imply that the purchase of electricity from third parties in a wholesale transaction is the preferred method of fulfilling a retail seller's obligation to comply with this article.

(h) Construction, alteration, demolition, installation, and repair work on an eligible renewable energy resource that receives production incentives or supplemental energy payments pursuant to Section 383.5, including, but not limited to, work performed to qualify, receive, or maintain production incentives or supplemental energy payments is "public works" for the purposes of Chapter 1 (commencing with Section 1720) of Part 7 of Division 2 of the Labor Code.

SEC. 2. Section 399.16 is added to the Public Utilities Code, to read:

399.16. The commission may consider an electric generating facility that is located outside the state to be an eligible renewable energy resource if it meets the criteria described in Section 399.12 and all of the following requirements:

(a) It is located so that it is, or will be, connected to the Western Electricity Coordinating Council (WECC) transmission system.

(b) It is developed with guaranteed contracts to sell its generation, and demonstrates delivery of energy, to a retail seller or the Independent System Operator.

(c) It participates in the accounting system to verify compliance with the renewables portfolio standard by retail sellers, once established by the State Energy Resources Conservation and Development Commission pursuant to subdivision (b) of Section 399.13.



# Appendix C

## GLOSSARY

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**Annual procurement target** — the quantity of eligible renewable resources that a retail seller must procure within a particular year to reach the target of 20 percent of its retail sales procured from eligible energy resources no later than December 31, 2017.

**Baseline** — refers to the quantity of eligible renewable resources procured in 2001. For the baseline, “procurement” includes power sold to an investor owned utilities’ customers by the Department of Water Resources and power from a facility owned or contracted for by the investor owned utility, pursuant to SB 1078 Section 399.15 (a) (3).

**Biomass** — any organic material not derived from fossil fuels, including agricultural crops, agricultural wastes and residues, waste pallets, crates, dunnage, manufacturing, and construction wood wastes, landscape and right-of-way tree trimmings, mill residues that result from milling lumber, rangeland maintenance residues, and wood and wood waste from timbering operations.

**Capacity** — the maximum amount of electricity that a generating unit, power facility, or utility can produce under specified conditions. Capacity is measured in kilowatts or megawatts.

**Collaborative Staff** — the staff at the Energy Commission and the California Public Utilities Commission who have been designated as having special status to work collaboratively and participate in confidential deliberations concerning decision-making on the implementation of the RPS.

**Community choice aggregator**— as defined in AB 117 (Migden, Chapter 838, Statutes of 2001-2002) refers to any of the following entities, if that entity is not within the jurisdiction of a local publicly owned electric utility that provided electrical service as of January 1, 2003: any city, county, or city and county whose governing board elects to combine the loads of its residents, businesses, and municipal facilities in a community-wide electricity buyers program or any group of cities, counties, or cities and counties whose governing boards have elected to combine the loads of their programs, through the formation of a joint powers agency established under Chapter 5 (commencing with Section 6500) of Division 7 of Title 1 of the Government Code.

**Digester gas** — gas from the anaerobic digestion of organic wastes.

**Distributed generation** — small scale electricity generation facilities sited in or close to a load center or at a customers’ site.

**Electric service provider** — an entity such as a marketer or aggregator who provides electricity directly to an end-use customer in the direct-access market.

**Electrical corporations** — Pacific Gas and Electric Company, San Diego Gas and Electric Company, Southern California Edison Company, or other electrical corporations as defined by Public Utilities Code section 218, contributing funds to the Renewable Resource Trust Fund pursuant to Public Utilities Code section 381.

**End-use customer (end-user)** — a residential, commercial, agricultural, or industrial electric customer who buys electric power to be consumed as a final product (not for resale).

**Fossil fuel** — fuel comprised of hydrocarbon constituents, including coal, petroleum, or natural gas, occurring in and extracted from underground deposits, and mixtures or byproducts of these hydrocarbon constituents.

**Fuel cell** — an advanced energy conversion device that combines hydrogen-bearing fuels with air-borne oxygen in an electrochemical reaction to produce electricity very efficiently and with minimal environmental impact.

**Geothermal** — natural heat from within the earth, captured for production of electric power, space heating, or industrial steam.

**Grid** — the electrical transmission and distribution system linking power plants to customers through high power transmission line service.

**Incremental geothermal** — pursuant to PUC section 399.12 (a)(2), incremental geothermal refers to the electricity that can be produced from existing geothermal resource and is eligible to be counted toward an utility's required additional procurement rather than its baseline.

**Hydroelectric** — a technology that produces electricity by using falling water to turn a turbine generator, referred to as hydro. See also "small hydro."

**Investor-owned utility (IOU)** — synonymous with "electrical corporations" as defined herein.

**Landfill gas (LFG)** — gas produced by the breakdown of organic matter in a landfill (composed primarily of methane and carbon dioxide) or the technology that uses this gas to produce power.

**Marketer** — an agent for generation projects who markets power on behalf of the generator. The marketer may also arrange transmission, firming or other ancillary services as needed. Though a marketer may perform many of the same functions as a broker, a marketer represents the generator while a broker acts as a middleman.

**Market price referent** — refers to the cost of a non-renewable product used as a comparison to renewable products which are needed to satisfy a retail seller's RPS obligation pursuant to PUC section 399.15 (c). Further, pursuant to section 399.14 (f), procurement and administrative costs associated with long-term contracts entered into by an electrical corporation for eligible renewable resources, at or below the market price determined by the CPUC pursuant to subdivision (c) of section 399.15, shall be deemed reasonable per se, and shall be recoverable in rates.

**Megawatt (MW)** — one thousand kilowatts. One megawatt is about the amount of power to meet the peak demand of a large hotel.

**Megawatt hour (MWh)** — a unit of measure describing the amount of electricity consumed over time. It means one megawatt of electricity supplied for one hour. Two typical California households consume about a combined total of 1 MWh in an average month, one household consumes about 0.5 MWh.

**Metered** — the independent measurement with a standard meter of the electricity generated by a project or facility.

**Municipal solid waste (MSW)** — all solid, semi-solid, and liquid wastes, including garbage, trash, refuse, paper, rubbish, and demolition and construction wastes that can be processed and burned to produce energy.

**Ocean wave** — refers to an experimental technology that uses ocean waves to produce electricity.

**Ocean thermal**— refers to experimental technology that uses the temperature differences between deep and surface ocean water to produce electricity.

**Photovoltaic (PV)** — a technology that uses a semiconductor to convert sunlight directly into electricity.

**Procurement** — for the purposes of PUC section 399.14 (g), refers to a utility acquiring the renewable output of electric generation facilities that the utility owns or for which it has contracted.

**Public Goods Charge (PGC)** — a surcharge applied to the electric bills of IOU ratepayers used to support energy efficiency, public interest research, development and demonstration (RD&D), low income, and renewable energy programs. Also called *systems benefit charge*.

**Renewable energy credits (RECs)** —represents the separable bundle of non-energy or non-commodity attributes (environmental, economic, and social) associated with the generation of renewable electricity; the attributes of a given unit of renewable generation, separated from the underlying electrical energy. Green tag, green ticket, and tradable renewable certificate (TRC) are often used synonymously with REC.

**Renewable** — a power source other than a conventional power source within the meaning of Section 2805 of the Public Utilities Code, provided that a power source utilizing more than 25 percent fossil fuel is not included. Section 2805 states: “ ‘Conventional power source’ means power derived from nuclear energy or the operation of a hydropower facility greater than 30 megawatts or the combustion of fossil fuels, unless cogeneration technology, as defined in Section 25134 of the Public Resources Code, is employed in the production of such power.”

**Renewables Portfolio Standard (RPS)** — for the purposes of this document, the term refers to California’s Renewables Portfolio Standard pursuant to SB 1078. In PUC section 399.12 (c) the law states that, “‘renewables portfolio standard’ means the specified percentage of electricity generated by eligible renewable energy resources that a retail seller is required to procure....”. Under the RPS, an electrical corporation must increase its total procurement of eligible renewable energy resources by at least an additional 1 percent of retail sales per year so that 20 percent of its retail sales are procured from eligible energy resources no later than December 31, 2017.

**Repower(ed)** — generically refers to replacing a significant portion of the generating equipment at an existing facility.

**RPS Collaborative Workplan** — a written description of how the Energy Commission and the CPUC will work together to implement the RPS, including laying out a three-phased schedule to categorize and sequentially address issues as appropriate. The designated collaborative staff of the Energy Commission and the CPUC developed the RPS Collaborative Workplan.

**Small hydro** — a facility employing one or more hydroelectric turbine generators, the sum capacity of which does not exceed 30 megawatts. Pursuant to PUC section 399.12, procurement from a small hydro facility as of January 1, 2003 is eligible only for purposes of establishing the baseline of an electrical corporation. A new small hydro facility is not eligible for the RPS if it will require a new or increased appropriation or diversion of water under Part 2 (commencing with Section 1200) of Division 2 of the Water Code. Pursuant to PUC section 383.5 (d) (2) (C) (iv), a new small hydro facility must not require an increased appropriation of water under Part 2 (commencing with Section 1200) of Division 2 of the Water Code to be eligible for supplemental energy payments.

**Supplemental Energy Payments (SEP)** — incentive payments from the Energy Commission to eligible renewable generators for the costs above the market referent of energy procured to meet the RPS, pursuant to PUC section 399.15 (a) (2). Any indirect costs from procuring eligible renewable resources – such as imbalance energy charges, sale of excess energy, decreased generation from existing resources, or transmission upgrades – are not eligible for SEP. The cost of the contract bids for renewable resources that are selected by the utilities to meet their RPS obligation will be compared to the cost of a comparable non-renewable product, the market price referent. Costs for renewable products that exceed the referent, excluding indirect costs noted above, will be covered by the SEP, subject to availability of Public Goods Charge (PGC) funds, pursuant to PUC section 399.15 (a) (4). The Energy Commission will distribute the SEP directly to the renewable generator through its New Renewable Facilities Program.

**Tidal current power** – energy obtained by using the motion of the tides to run water turbines that drive electric generators.

**Transmission system** — an interconnected group of electric transmission lines and associated equipment to move or transfer electric energy in bulk between points of supply and consumption.

**Western Electricity Coordinating Council (WECC)** — formed on April 18, 2002, by the merger of the Western Systems Coordinating Council (WSCC), Southwest Regional Transmission Association (SWRTA), and Western Regional Transmission Association (WRTA). WECC is responsible for coordinating and promoting electric system reliability, assuring open and non-discriminatory transmission access among members, and providing a forum for resolving transmission access disputes.

**WECC interconnection** — the junction where radial lines from a given power plant interconnect to the WECC-controlled transmission system.

**Wind power**— energy from wind converted into mechanical energy and then electricity.

# Appendix D

## ACRONYMS

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AB	—	Assembly Bill
APX	—	Automated Power Exchange
AReM	—	Alliance of Retail Energy Markets
CalWEA	—	California Wind Energy Association
CCA	—	community choice aggregator
CEERT	—	Center for Energy Efficiency and Renewable Technologies
CEI	—	Chateau Energy, Inc.
CPM	—	Clean Power Markets
CPUC	—	California Public Utilities Commission
ESP	—	electric service provider
GMMs	—	generator meter multipliers
IEP	—	Independent Energy Producers
IOU	—	investor owned utility
ISO	—	Independent System Operator
kWh	—	kilowatt-hour
LFG	—	landfill gas
MSW	—	municipal solid waste
MW	—	megawatt
mWh	—	megawatt-hour
NRFP	—	New Renewable Facilities Program
PGC	—	Public Goods Charge
PPA	—	power purchase agreement
PUC	—	Public Utilities Code
PV	—	photovoltaic
REC	—	renewable energy credit
REI	—	Renewable Energy, Inc.
REP	—	Renewable Energy Program
RPS	—	Renewable Portfolio Standard
SB	—	Senate Bill
SEP	—	supplemental energy payments
TURN	—	The Utility Reform Network
WECC	—	Western Electricity Coordinating Council
WGA	—	Western Governors Association