STATE OF CALIFORNIA ARNOLD SCHWARZENEGGER, *Governor*

PUBLIC UTILITIES COMMISSION
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3298

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TO PARTIES OF RECORD IN RULEMAKING 06-04-009

This is the proposed decision of President Peevey and Administrative Law Judge (ALJ) Gottstein. It will not appear on the Commission's agenda for at least 30 days after the date it is mailed. The Commission may act then, or it may postpone action until later.

When the Commission acts on the proposed decision, it may adopt all or part of it as written, amend or modify it, or set it aside and prepare its own decision. Only when the Commission acts does the decision become binding on the parties.

Parties to the proceeding may file comments on the proposed decision as provided in Article 14 of the Commission's **Rules of Practice and Procedure** (Rules), accessible on the Commission's website at www.cpuc.ca.gov. Pursuant to Rule 14.3, opening comments shall not exceed 25 pages.

Comments must be filed either electronically pursuant to Resolution ALJ-188 or with the Commission's Docket Office. Comments should be served on parties to this proceeding in accordance with Rules 1.9 and 1.10. Electronic copies of comments should be sent to ALJ Gottstein at meg@cpuc.ca.gov and Commissioner Peevey's advisor Nancy Ryan at ner@cpuc.ca.gov. All parties must serve hard copies on the ALJ and the Assigned Commissioner, and for that purpose I suggest hand delivery, overnight mail, or other expeditious method of service. The current service list for this proceeding is available on the Commission's website at www.cpuc.ca.gov.

/s/ JANET A. ECONOME for
Angela K. Minkin, Chief
Administrative Law Judge

ANG:tcg

Attachment

Decision <u>**PROPOSED DECISION OF PRESIDENT PEEVEY AND ALJ GOTTSTEIN**</u> **(Mailed 12/13/2006)**

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Implement the Commission's Procurement Incentive Framework and to Examine the Integration of Greenhouse Gas Emissions Standards into Procurement Policies.	Rulemaking 06-04-009 (Filed April 13, 2006)

INTERIM OPINION ON PHASE 1 ISSUES: GREENHOUSE GAS EMISSIONS PERFORMANCE STANDARD

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**INTERIM OPINION ON PHASE 1 ISSUES:
GREENHOUSE GAS EMISSIONS PERFORMANCE STANDARD**

1. Introduction and Summary[1]

Today, we adopt an interim greenhouse gas (GHG) emissions performance standard for new long-term financial commitments to baseload generation undertaken by all load-serving entities (LSEs), consistent with the requirements and definitions of Senate Bill (SB) 1368 (Stats. 2006, ch. 598).[2] Our adopted emissions performance standard or "EPS" is intended to serve as a near-term bridge until an enforceable load-based GHG emissions limit is established and in operation.[3] At that time, as directed by SB 1368, we will reevaluate and continue, modify or replace this standard through a rulemaking proceeding, and in consultation with the California Energy Commission (CEC) and the California Air Resources Board (CARB).

As discussed in this decision, an EPS is similar to an energy efficiency appliance standard. If a consumer wants to purchase a new refrigerator in California, for example, he or she has a variety of models to choose from--each with a different upfront purchase price, operating cost and other design attributes. However, at a minimum, each refrigerator must meet the threshold for appliance efficiency established by the standard. Similarly, SB 1368

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[1] Attachment 1 describes the abbreviations and acronyms used in this decision.

[2] Attachment 3 presents the full text of SB 1368. The statute defines LSEs as "every electrical corporation, electric service provider, or community choice aggregator serving end-use customers in the state." (Public Utilities Code § 8340(h), added by SB 1368). All subsequent references to sections refer to the Public Utilities Code, unless otherwise specified.

establishes a minimum performance requirement for any baseload generation facility that represents a new long-term financial commitment entered into by entities providing power to California ratepayers.[4] The new law establishes that the GHG emission rates for these facilities must be no higher than the GHG emissions rate of a combined-cycle gas turbine (CCGT) powerplant.[5]

An EPS is needed to reduce California's financial risk exposure to the compliance costs associated with future GHG emissions (state and federal) and associated future reliability problems in electricity supplies. Put another way, it is needed to ensure that there is no "backsliding" as California transitions to a statewide GHG emissions cap: If LSEs enter into long-term commitments with high-GHG emitting baseload plants during this transition, California ratepayers will be exposed to the high cost of retrofits (or potentially the need to purchase expensive offsets) under future emission control regulations. They will also be exposed to potential supply disruptions when these high-emitting facilities are taken off line for retrofits, or retired early, in order to comply with future regulations. A facility-based GHG emissions performance standard protects California ratepayers from these backsliding risks and costs during the transition

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[3] We use the terms "GHG emissions performance standard," "standard," and "emissions performance standard" (or "EPS") interchangeable throughout this decision.

[4] SB 1368 directs this Commission to adopt an EPS for all LSEs, as that term is defined above, and directs the CEC to implement an EPS for all of the local publicly owned electric utilities (by June 30, 2007) consistent with the standard we adopt herein. (§ 8341(e)).

[5] Throughout this decision, we use the term CCGT powerplant to refer to a "combined cycle natural gas plant" as defined in SB 1368. More specifically, CCGT powerplant refers to a powerplant that "employs a combination of one or more gas turbines and steam turbines in which electricity is produced in the steam turbine from otherwise lost waste heat exiting from one or more of the gas turbines." (§ 8340(b).)

to a load-based GHG emissions cap. As directed by SB 1368, we have considered the effects on system reliability and overall costs to electricity customers in developing an EPS that will achieve these objectives.[6]

SB 1368 provides specific direction on many design and implementation aspects of the EPS. We briefly describe that direction in the following summary of today's adopted standard.

1.1. Covered Procurements

SB 1368 describes what types of generation and financial commitments will be subject to the EPS ("covered procurements"). Under SB 1368, the EPS applies to "baseload generation," but the requirement to comply with it is triggered only if there is a "long-term financial commitment" by an LSE. The statute defines baseload generation as "electricity generation from a powerplant that is designed and intended to provide electricity at an annualized plant capacity factor of at least 60%."[7] For LSE-owned baseload generation, a long-term financial commitment occurs when there is a "new ownership investment." For baseload generation procured under contract, there is a long-term commitment when the LSE enters into "a new or renewed contract with a term of five or more years."[8]

SB 1368 provides that CCGT baseload powerplants currently in operation, or that have a CEC final permit decision to operate as of June 30, 2007, shall be

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[6] § 8341 (d)(6).

[7] § 8340 (a).

[8] § 8340 (j).

"deemed to be in compliance" with the EPS. We refer to these § 8341(d)(1) grandfathered powerplants as "deemed-compliant" CCGT powerplants.

During the workshop process and in their comments, parties debated the issue of how the EPS applies to existing facilities owned by the LSE and used to serve its load (referred to as "retained generation"). Based on our reading of SB 1368, we find that the "new ownership investment" trigger for EPS compliance includes LSE investments in retained generation. Except for deemed-compliant CCGTs, we define that trigger as any LSE investment that is intended to extend the life of one or more units of an existing baseload powerplant for five years or more, or results in a net increase in the existing rated capacity of the powerplant.[9] Only those units in a multi-unit generating facility that are being added, replaced or altered must comply with the EPS. A new ownership investment is also triggered if the investment is intended to convert an existing non-baseload powerplant to a baseload powerplant.

However, for deemed-compliant CCGT baseload powerplants, we conclude that the type of investment described above does not necessarily trigger a requirement to comply with the EPS—for either LSE-owned CCGT powerplants (under the "new ownership investment" trigger) or for non-LSE owned powerplants (under the "new or renewal contract" trigger). As discussed in this decision, to construe SB 1368 otherwise would violate fundamental rules of statutory construction by rendering certain sections meaningless or redundant. At the same time, we find that SB 1368 cannot be construed to mean

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[9] "Rated capacity" refers to the nameplate capacity of the plant, i.e., the plant's maximum rated output under specific conditions designated by the manufacturer and usually indicated on the nameplate physically attached to the generator.

that all new capacity added to a deemed-compliant CCGT powerplant should also be excused from demonstrating actual compliance with the EPS. This would achieve an absurd result by allowing an owner of a deemed-compliant CCGT powerplant to circumvent the EPS by simply co-locating additional units and capacity with existing units at a previously deemed-compliant powerplant.

To avoid this absurd result and give meaning to each section of the statute, we require that units added to a deemed-compliant CCGT powerplant that result in an increase of 50 megawatts (MW) or more to the powerplant's rated capacity must meet the EPS. We select a 50 MW threshold because it demarcates the boundary between significant and minor changes in generating capacity for the purpose of triggering CEC powerplant permitting requirements under Public Resources Code § 25123. This means that an LSE must demonstrate compliance with the EPS whenever the LSE adds units to one of its own deemed-compliant CCGT powerplants if those additions result in an increase of 50 MW or greater to the powerplant's rated capacity. In addition, the LSE must demonstrate compliance with the EPS whenever it enters into new or renewal contract with a deemed-compliant CCGT powerplant to which units have been added that result in an increase of 50 MW or greater to the powerplant's rated capacity.[10] In both cases, however, only the added units must meet the EPS.

Some parties urge us to also require that investor-owned utilities demonstrate compliance with the EPS any time the utility seeks rate

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[10] For the purpose of establishing when there has been a 50 MW addition, the existing rated capacity will be determined as follows: 1) for all CCGT plants that are in operation on the effective date of this decision—the rated capacity of the plant that is operating, or 2) for all other plants (or additions to plants) that obtain a CEC final permit to operate by June 30, 2007—the rated capacity authorized by the permit.

modifications or submits procurement plans supporting retained baseload generation, irrespective of whether new investments are made to those facilities. This position is inconsistent with the plain language of SB 1368, which provides clear direction as to what triggers the requirement to apply the EPS. Therefore, we only require a demonstration of EPS compliance for retained baseload generation when the LSE makes a new investment in those facilities, as discussed above.

In sum, the interim EPS will apply to the following long-term financial commitments made by an LSE to baseload generation ("covered procurements"):

(1) New ownership investments in baseload generation made by an LSE, defined as:

(a) Investments in new baseload powerplant (new construction).

(b) Acquisition of new or additional ownership interest in existing baseload powerplant previously owned by others.

(c) New investments in the LSE's own existing, non-CCGT baseload powerplants that are: 1) intended to extend the life of one or more units by five years or more, 2) result in a net increase in the rated capacity of the powerplant, or 3) intended to convert a non-baseload plant to a baseload plant, or

(d) Units added to a deemed-compliant CCGT plant that result in an increase of 50 MW or more to the powerplant's rated capacity, or

(2) New contract commitments (including renewal contracts) of five years or greater by an LSE with:

(a) baseload generation facilities, unless those facilities represent deemed-compliant CCGT powerplants, or

(b) any deemed-compliant CCGT powerplant that added units resulting in an increase of 50 MW or more to the powerplant's rated capacity. (The contracting LSE need only show that the added units meet the EPS).

1.2. EPS Performance Level (Emissions Rate)

Pursuant to SB 1368, the performance level of the EPS must be "no higher" than the emissions rate of a CCGT powerplant.[11] However, the statute does not specify the emissions rate for a CCGT. Based on our review of emissions rates associated with a broad range of CCGT powerplants of varying vintages, we adopt an EPS emissions rate of 1,000 pounds of carbon dioxide (CO_2) per megawatt-hour (MWh).[12] We select a level that is somewhat above the 2004-2005 weighted average of the reported data in CEC's Continuous Emissions Monitoring System, but lower than the emission rates associated with the oldest, most inefficient "deemed-compliant" CCGT powerplants still in operation. Based on the record in this proceeding, we find that this level reflects the intent of the Legislature to base the EPS on representative CCGT emission rates. At the same time, our adopted level avoids establishing a performance standard that is representative of the most inefficient, older CCGT powerplants currently in operation. We believe that this is appropriate in light of the statute's grandfathering provisions, which reflect the Legislature's concern that some of the older, less efficient CCGT powerplants in operation may not be able to meet the standard.

1.3. Application of EPS to Contracts

The threshold design issue debated in this proceeding was the application of the interim EPS to contracts. All parties agree that the characteristics of the

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[11] § 8341(d).

[12] We discuss in Section 4 below why today's adopted standard focuses on CO_2 emissions.

facility supplying the energy should be considered when applying the adopted standard to new ownership investments. However, there was considerable disagreement over whether the same should apply when considering contract commitments. The issue came down to whether we should apply the performance standard to the underlying facility or to the contracted-for deliveries.

In particular, when a summer product delivered under a new or renewal contract (with a term of five years or greater) from a baseload facility represents less than 60% of that facility's annual average output, some parties recommend that the contract be considered "non-baseload" and therefore exempt from the standard. Similarly, some parties recommend that only the amount of contracted-for deliveries from customer generators to the LSE should determine whether or not the standard applies to the contract.

Several parties also recommend that the capacity factors and emission rates of multiple powerplants be "blended" when two or more deliver power under a single contract. Under our refrigerator analogy, this approach would permit a customer to purchase two different refrigerator models, one that does not meet the minimum level of efficiency under the appliance standard and one that is more efficient than the standard, such that the average efficiencies of the two meet the required efficiency performance level. The blending approach suggested by parties in the context of the EPS would also permit the averaging of plant capacity factors to determine whether or not the standard applies. In practice, this means that a powerplant generating electricity at a 60% or greater annualized capacity factor (baseload generation) might not be subject to the EPS if the contract also includes deliveries from a powerplant generating electricity at a capacity factor below 60%, depending upon the relative amount of power to be delivered by each facility.

We find that the goals of SB 1368 and this Commission's GHG reduction policies requires us to look at the characteristics and emissions of each individual powerplant being contracted for, *not* just the characteristics of the contracted-for-deliveries or the blended combination of multiple facilities or resources. Indeed, as discussed throughout this decision, it is the very characteristics of the powerplants underlying long-term financial commitments that create the potential financial and reliability risks to California consumers that this Commission and the Legislature seek to reduce through the EPS. Moreover, the rules of statutory construction support a facility-based application of the standard. In particular, SB 1368 directs:

> "In determining whether a long-term financial commitment is for baseload generation, the commission ***shall consider the design of the powerplant and the intended use of the powerplant…*** " [13]

Accordingly, the rules we adopt today require a facility-based application of the EPS. Determinations as to whether the facility is a baseload powerplant, and if so, whether its GHG emissions rate meets the EPS will be based on the characteristics of each generating source underlying the contract, including contracts with renewable resources where the contracted-for deliveries are firmed with a non-renewable resource.

1.4. Unspecified Contracts

SB 1368 also directs us to address long-term purchases of electricity from unspecified sources in a manner consistent with the statute.[14] We considered in this proceeding whether it would be consistent with the statute to impute a specific emissions rate to unspecified contracts[15] and, if so, what proxy rate to utilize for this purpose.

As discussed in this decision, consistency with SB 1368 requires us to address unspecified contracts in a manner that ensures the following:

(1) LSEs only enter into long-term financial commitments with baseload generation that comply with the EPS, and

(2) EPS compliance cannot be achieved in a manner that would yield a contrary result, i.e., that permits an LSE to enter into long-term commitments with high-emitting sources.

In considering how best to achieve these objectives, we examined various approaches presented during the workshop process and in written comments for imputing an emissions value to unspecified contracts. These include approaches that use 1) Western Energy Coordinating Council (WECC) calculations of average emissions rates for generation activities throughout the western states or by specific geographic region, and 2) the California Net Power Mix information produced by the CEC for power content labeling. Based on the record in this proceeding, we conclude that consistency with SB 1368 requirements cannot be achieved using an approach that imputes emissions rates to unspecified contracts, for several reasons.

First, we have difficulty reconciling the concept of imputed emissions rates with the requirements of SB 1368 since, by definition, such proxies do not reflect

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[13] § 8341 (b) (4), emphasis added.

[14] § 8341(d)(7).

[15] We use the term "unspecified contracts" to refer to contracts (power purchase agreements) that are not linked to any particular generating source, although in some instances the type of fuel or heat rate of the contract may be specified.

the actual emissions from a resource. As a result, using imputed emissions rates does not permit us to determine whether a commitment with an unspecified resource is consistent with SB 1368 or simply exacerbates the problems this Commission and the Legislature are trying to address.

Moreover, any method to impute a GHG emissions rate to unspecified resources results in a binary outcome in the context of an EPS—that is, all financial commitments with unspecified resources will either "pass" or "fail" based on the selected level of imputed emissions. As a result, there is enormous pressure to game the methodology and input assumptions used for this purpose, thereby making it very difficult and contentious to implement this particular approach to addressing unspecified contracts. Finally, as discussed in Section 4.12, one of the specific proxy approaches recommended by Commission staff or in parties' comments are reasonable or workable for our purposes, at least not at this time.

Therefore, instead of imputing an emissions rate to unspecified contracts, we require in today's decision that all covered procurements be with specified resources that can demonstrate compliance with the interim EPS. This approach is fully consistent with SB 1368 since it ensures that "any" and "all" long-term financial commitments with baseload generation will meet the EPS, as the statute so directs.[16] Moreover, it cannot be gamed in a manner that could result in the opposite result than the statute intended, i.e., an *increasing* number of long-term commitments to high GHG-emitting resources.

[16] § 8341 (a), (b)(1), (b)(3) and (d)(1).

Based on the record in this proceeding, we also conclude that it is highly unlikely that LSEs will need to enter into any new or renewal power purchase contracts of five years or greater that are unspecified during the transition to a statewide GHG emissions limit. Therefore, requiring that all long-term contracts with baseload generation be "specified" in order to demonstrate EPS compliance should not have a significant, if any, impact on an LSE's resource procurement flexibility. As discussed in this decision, in the event that an LSE must enter into a long-term unspecified contract to address system reliability concerns, it may request Commission consideration of a reliability exemption from this requirement, on a case-by-case basis.

A requirement that long-term power purchase contracts specify the underlying generation facilities is also consistent with our discussion of emissions registration in Decision (D.) 06-02-032 and a logical interim step towards the implementation of Assembly Bill (AB) 32 (Stats. 2006, ch. 488).[17] As we note in today's decision, other jurisdictions have developed specific resource tagging mechanisms to track generation attributes, including GHG emissions, of resources within their control areas. In addition, the CEC has under development the Western Renewable Energy Generation Information System for purposes of tracking compliance with California's Renewable Portfolio Standard (RPS) statute.[18] In our view, it is entirely feasible to implement a program that

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[17] See D.06-02-032, p. 38. Among other things, AB 32 requires CARB to adopt a statewide GHG emissions limit equivalent to the statewide GHG emissions levels in 1990, to be achieved by 2020, in consultation with this Commission.

[18] By law, electricity generated from eligible renewable energy resources must equal at least 20% of the total electricity sold to retail customers in California per year by December 31, 2010. (SB 107, Stats. 2006, ch. 464).

tracks the GHG emissions of all generating units, and that would enable marketers and other sellers of unspecified resource contracts to assign a reasonable and accurate GHG emissions profile to their contracts. This should be the strategy pursued by California to deal with emissions from any unspecified resource contracts that LSEs may wish to pursue; however, as the record shows, this is not a likely pursuit for the types of LSE long-term procurements subject to the interim EPS.

1.5. Calculation of Emissions Associated with Cogeneration

SB 1368 requires us to adopt a methodology for calculating the emissions rate associated with cogeneration facilities that recognizes both the thermal output (heat or steam) and electrical output associated with cogeneration.[19] In today's decision, we consider several approaches to this requirement and adopt the "conversion method." Under this method, the emissions rate is calculated by dividing the total GHG emissions from a cogeneration facility by the sum of its kilowatt-hour (kWh) output plus the usable thermal energy output (expressed in kWh) produced by the facility. For this calculation, the thermal energy output is converted from British thermal unit (Btu) into a kWh equivalent using the standard engineering conversion factor of 3413 Btu per kWh.

There was some debate in this proceeding over how to define "useful thermal energy" for this calculation. We adopt the definition used by the Federal Energy Regulatory Commission (FERC) in its regulations mandating the

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[19] § 8341(d)(3).

minimum efficiencies of a cogeneration qualifying facility (QF).[20] Based on this definition, the calculation of emissions rates for cogeneration facilities should include the thermal energy that is actually intended to be delivered to the thermal host, and not include remaining thermal energy intended to be exhausted as waste heat.

As discussed in this decision, all existing cogeneration facilities complete an annual questionnaire submitted to the interconnecting utility to demonstrate compliance with FERC efficiency requirements. On this form, the cogenerator presents monthly and annual values for energy input, useful power output and useful thermal output. For the purpose of the interim EPS, we will base a cogenerator's emission rates on the values presented in these questionnaires, which are readily available from the interconnected utility. For new cogeneration facilities, when this questionnaire has not been submitted to the utility, the EPS will be determined based on reasonably projected emissions of the facility, which can be based on readily available information in FERC Form 556, required for QF certification.

We emphasize, however, that we adopt the above approach for calculating and documenting cogeneration emissions rates for the limited purpose of demonstrating compliance with the interim EPS. Our determinations today are in no way intended to prejudge or predetermine what approach may be established in the context of our Procurement Incentive Framework or under the statewide GHG emissions limit envisioned under AB 32.

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[20] A QF is a generating facility that meets the requirement for QF status under federal law and FERC regulations governing such facilities. QFs can be cogeneration facilities

Footnote continued on next page

1.6. Emissions Rates of Renewables and "Null" Renewable Power

As summarized in Figure 1, the record in this proceeding supports an upfront determination that the following renewable resources and technologies are EPS-compliant:

- Solar Thermal Electric
- Wind
- Geothermal, with or without reinjection
- Generating facilities (e.g., agricultural and wood waste, landfill gas) using biomass that would otherwise be disposed of utilizing open burning, forest accumulation, landfill (uncontrolled, gas collection with flare, gas collection with engine), spreading or composting.

In particular, the record shows that electric generation using biomass (e.g., agricultural and wood waste, landfill gas) that would otherwise be disposed of under a variety of conventional methods (such as open burning, forest accumulation, landfills, composting) results in a substantial *net reduction* in GHG emissions. This is because the usual disposal options for biomass wastes emit large quantities of methane gas, whereas the energy alternatives either burn the wastes that would become methane or burn the methane itself, generating CO_2. Since methane gas is some twenty-five times more potent as a GHG than CO_2, and since the two gases have similar atmospheric residence times, trading off

of any size or small power production facilities (up to 80 MW) where the primary energy source is renewable.

methane for CO_2 emissions from energy recovery operations leads to a net reduction of the greenhouse effect.[21]

In practice, this means that an LSE does not have to demonstrate compliance with the EPS for long-term financial commitments with baseload generation utilizing any of the renewable resources and technologies listed above. Such commitments get an automatic "pass" through the gateway screen described below.

There was considerable debate over how to attribute emissions factors to renewable resources that have sold off their renewable energy credits or "RECs". The term "null renewable power" refers to those renewable resources that have transferred their renewable attributes through the sale of RECs. In the context of making the EPS "go, no-go" commitment decision, parties raised the issue of whether renewable resources should be "stripped" of their GHG emissions attributes if they have sold RECs and if so, what emissions rate should be assigned to that null renewable power for the purpose of evaluating EPS compliance.

As discussed in this decision, among other potential purposes, the trading of RECs would provide a flexible compliance option to LSEs for meeting their RPS obligations. We have identified the investigation of a tradable REC system as one of the tasks for Rulemaking (R.) 06-02-012 and plan to initiate this

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[21] For the biomass technologies identified above, which utilize landfill gas, agricultural and wood waste as the biomass fuel source, by definition there are no emissions associated with growing the fuel. As discussed in this decision, an LSE entering into a long-term financial commitment with a biomass generating project where the growing the fuel is required will need to calculate net emissions taking into account the emissions associated with "growing," as well as "processing and generating" the electricity from the fuel source pursuant to § 8341(d)(4).

investigation during 2007. We therefore cannot predict at this time whether, how or when a regulatory REC market will develop in California. Some parties propose that we defer the issue of how to treat null renewable power for the purpose of EPS-compliance until we complete our investigation of a tradable REC system. However, we reject this approach because of the potentially dampening effect that this uncertainty could have on the development of renewable resources.

For the purposes of demonstrating compliance with the interim EPS, we determine that the emissions rate for renewables should be calculated based on the operations and emissions profile of the renewable resource, irrespective of whether RECs associated with that facility are sold. We reach this determination for several reasons. In particular, we conclude that stripping renewables of their emissions profile if RECs are sold could easily create a "perverse" result, namely, to discourage long-term commitments with renewable generators that have zero, low or even negative net GHG emission profiles, in favor of higher emitting facilities.

Moreover, in the context of EPS compliance, we find that retaining the emissions attributes of the renewable facility when RECs are sold does not create a double counting problem, as some suggest in this proceeding. This is because the EPS is a "go-no go" investment standard separate from RPS compliance, and as discussed above, each facility has to pass the EPS on its own emissions-generating merits. In other words, a high emitting facility would not be able to use a purchased REC for the purpose of reducing (or blending) its emissions to demonstrate compliance with the EPS. Therefore, there is nothing to double count here, since RECs would not have any value for EPS-compliance. Moreover, our treatment of RECs in the context of the EPS is not inconsistent with § 399.12, as amended by SB 107, which provides that a REC "includes all renewable and environmental attributes associated with the *production* of electricity" (emphasis added), not discrete investment decisions.

For these and other reasons, we determine that the emissions profile of a renewable resource will not change for the purpose of demonstrating EPS compliance if or when the owner sells the RECs associated with that baseload facility. This also means that purchased RECs cannot be used by an LSE to lower the emissions of a baseload facility for the purpose of demonstrating EPS compliance. However, we emphasize that today's determination on how to treat null renewable power and associated RECs is specific to the application of the interim EPS. This determination in no way guarantees that null renewable power will be assigned a zero or low GHG emissions value in the context of either the Procurement Incentive Framework we are implementing in Phase 2 of this proceeding, or the statewide GHG emissions limits adopted by the Legislature in AB 32.

1.7. Exemptions from the Interim EPS

As discussed above, SB 1368 exempts from the EPS any CCGT baseload powerplant that is in operation, or that obtains a final CEC permit to operate by June 30, 2007. By today's decision, we provide for the possibility of a reliability exemption to the EPS that is very limited in scope. We also provide for the possibility of filing a petition for modification to obtain relief from the requirements of this decision in the event of extraordinary circumstances not contemplated by SB 1368 and this decision.

First, we allow for case-by-case exemptions to the EPS if the LSE can demonstrate that a long-term commitment to a non-compliant powerplant is necessary to address system reliability concerns. As discussed in this decision, we believe that this type of exemption will probably not be needed, given the definition of covered procurements and other design aspects of the EPS. Nonetheless, we allow for the possibility of granting this limited exemption, on a case-by-case basis, in the event that unexpected reliability problems arise during implementation.

Second, we permit an LSE to file a petition for modification in the event of "extraordinary circumstances, catastrophic events, or threat of significant financial harm" that may arise during EPS implementation due to unforeseen circumstances not contemplated by SB 1368 and this decision. As in the case of a reliability exemption, our consideration of such a petition for modification comes with a heavy burden of proof on the LSE, as it must be based on extreme (and therefore highly unlikely) circumstances. Both the reliability exemption and the request for relief due to "extraordinary circumstances" must be pre-approved on a case-by-case basis by the Commission. As directed in this decision, LSE requests for pre-approval of a reliability exemption shall be made by application. LSE requests for relief from the requirements of this decision due to "extraordinary circumstances" shall be made by filing a petition for modification.

Additional exemptions from the EPS were proposed in this proceeding for (1) "small size" facilities, contracts or service territories, (2) research development and demonstration (RD&D) projects with the potential to develop a lower-emitting resource in the future, (3) gas-fired cogeneration and (4) case-by-case exemptions based on the cost of compliance. These recommendations were debated on both sides in parties' comments and legal briefs. For the reasons discussed in Section 4.8, we find that none of these exemptions are reasonable in light of the policy objectives and statutory requirements of SB 1368.[22] We also find that requiring QFs to comply with the GHG emissions performance standard is consistent with federal law, and conclude that we cannot grant QFs an exemption from the requirements of SB 1368 as some parties request.

In addition, a few parties recommend that we permit LSEs to obtain "offsets," whereby the LSE would have the option to offset emissions from a high-emitting baseload resource with GHG emissions reductions secured elsewhere to bring it into compliance with the EPS. Continuing with our appliance efficiency analogy, permitting the LSE to comply with the EPS in this manner would be akin to allowing customers to purchase refrigerators that do not meet the minimum level of efficiency for their own home, as long as they create offsetting efficiency savings in a neighbor's home, e.g., by changing out enough inefficient light bulbs with efficient ones (or paying a third party to do it). One party also suggests that we allow the LSE to average emissions rates across its entire procurement portfolio in demonstrating compliance with the standard.

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[22] As we discuss in this decision, the Legislature specifically directs that we not count CO_2 injected into geological formations (so as to prevent releases into the atmosphere) in the calculation of net emissions. Therefore, although we do not adopt a blanket RD&D exemption from the EPS, we do clarify how the LSE may apply for Commission pre-approval of covered procurements utilizing such CO_2 sequestration projects. In implementing §§ 8341(d)(2) and (5), we also clarify that we will determine EPS compliance for such covered procurements based on reasonably projected net emissions over the life of the facility, which recognizes that the sequestration project may become operational after the powerplant comes on line or the LSE enters into the contract.

We conclude that permitting LSEs to comply with the EPS through offsets or portfolio-averaging would compromise the very purpose articulated by this Commission and the Legislature for establishing an interim EPS in the first place. As discussed above, the EPS establishes a minimum level of acceptable GHG emissions performance for any baseload generation facility that represents a new long-term financial commitment to California. This serves a fundamentally different purpose, reflecting different policy objectives, than programs to reduce GHG emissions through a portfolio-wide cap, cap-and-trade programs or programs that permit LSEs to create or purchase offsets to meet an emissions cap or performance standard. As discussed in Section 5.4, the purpose of these programs is to provide varying degrees of compliance flexibility when the primary policy goal is to reduce the overall level of emissions generated through procurement activities.

The objective of the interim EPS, on the other hand, is to ensure that there is no "backsliding" as California transitions to a statewide GHG emissions cap. This objective cannot be accomplished if LSEs are permitted to comply with the standard by diluting the emissions from high-emitting powerplants through portfolio averaging, or by increasing the permissible level of emissions for non-compliant powerplants through offsets or other means.[23] These options would only serve to disguise the types of problems that the EPS is designed to avoid, e.g., the high costs of future plant retrofits and reliability disruptions as it

[23] For similar reasons, we also reject the notion of establishing "price caps" for complying with today's adopted EPS, as one party proposes. As discussed in Section 4.8.5, price caps would allow the LSE to build or enter into long-term contracts with high GHG-emitting plants without any reduction in those plants' emissions, which is not consistent with the purpose of establishing an interim EPS in the first place.

becomes increasingly difficult for these high-emitting facilities to comply with GHG emission regulations, such as the AB 32 declining cap on statewide GHG emissions.[24]

Moreover, as staff and many parties point out, a workable offsets program cannot be designed and implemented within the timeframe contemplated for an interim EPS, particularly in light of the SB 1368 statutory requirement that an enforceable EPS be put in place no later than February 1, 2007.

For these reasons, we do not permit offsets or portfolio averaging in the context of the adopted interim EPS. In the context of a load-based cap, however, we fully intend to evaluate a broad range of flexible compliance options as we proceed to implement the Procurement Incentive Framework during Phase 2 of this proceeding. Pursuant to AB 32, flexible compliance options will also be evaluated as California proceeds to implement the emissions limits required under that new law on a statewide basis.[25] As we stated in D.06-02-032, we will focus our efforts during Phase 2 on ensuring that the compliance options that we do permit under the Procurement Incentive Framework are credible, verifiable and administratively feasible. During Phase 2, we intend to carefully explore the pros and cons of alternate proposals for offsets, trading, banking and borrowing and other compliance options before making our final determinations. Throughout the process, we will closely coordinate with CARB, the Governor's Climate Action Team as well as other state, regional or federal agencies that are exploring design options for cap-and-trade programs.[26]

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[24] AB 32, § 38562(c).

[25] AB 32, § 38561, § 38570.

[26] D.06-02-032, p. 44.

1.8. Demonstrating Compliance with the EPS

Attachment 2 presents a flowchart illustrating how the EPS will be applied under today's adopted rules, consistent with SB 1368. We take a gateway screen approach, as recommended by Commission staff and all the parties to this proceeding. This approach is consistent with the intent of SB 1368, which directs us to look to the "design and the intended use" of the powerplant under § 8340(a). Moreover, as staff and the parties point out, a gateway screen approach is the most practicable and enforceable manner in which to determine EPS compliance.

As illustrated in Attachment 2, this approach applies a series of questions/criteria to first establish whether or not the LSE's financial commitment represents a covered procurement subject to the EPS. If it is, then the commitment is screened to ensure that it meets the performance level of the standard, e.g., that the associated GHG emissions rate does not exceed 1,000 lbs of CO_2 per MWh. Once the financial commitment successfully passes through the gateway screen, the LSE has demonstrated EPS compliance for that particular commitment. Ongoing Commission review or monitoring of the facilities underlying that commitment is not required.

We also describe in today's decision the procedures by which an LSE demonstrates compliance with this gateway screening process. Currently, Southern California Edison (SCE), San Diego Gas & Electric Company (SDG&E) and Pacific Gas and Electric Company (PG&E) bring all power purchase contracts with terms of five years or longer before this Commission for review and pre-approval by filing either an advice letter or application. As discussed in Section 5.1, we utilize these existing procedural vehicles for reviewing and pre-approving PG&E, SCE and SDG&E's covered procurements with respect to EPS compliance.

On the other hand, we do not currently require electric service providers, community choice aggregators or the small electrical corporations to submit procurement plans or power purchase contracts to the Commission for pre-approval. For these entities, we establish today an annual advice letter filing by which they can attest "after-the-fact" that they are in compliance with the EPS. They can also request Commission pre-approval of covered procurements as EPS-compliant (but are not required to) by advice letter. In today's decision, we also clarify the documentation requirements for all LSE compliance submittals, including any showings of "alternative compliance" by multi-jurisdictional electrical corporations pursuant to § 8341(d)(9).

2. Procedural Background

On October 6, 2005, we issued a Policy Statement on GHG Performance Standards (GHG Policy Statement) stating our intent to investigate the integration of GHG emissions standards into Commission procurement policies, including the Procurement Incentive Framework being developed in R.04-04-003.[27]

On February 16, 2006, we issued D.06-02-032 in R.04-04-003. In that decision, we adopted a load-based GHG emissions cap as the cornerstone of our Procurement Incentive Framework, noting that: "[e]stablishing a GHG cap is consistent with the Governor's objectives for climate change policy, as well as

[27] A copy of the GHG Policy Statement is included in Attachment 2 of the April 17, 2006 *Order Instituting Rulemaking* in this proceeding.

our own GHG Policy Statement."[28] Under a load-based cap, the LSEs would be subject to GHG emission limits for all resources procured to serve their load, no matter from what source, including imports. We made a number of preliminary determinations in D.06-02-032 to guide the next steps in implementing a load-based cap, but left most of the design details to a subsequent implementation phase.

On April 17, 2006, we opened this rulemaking to implement the load-based cap under our Procurement Incentive Framework and to examine the integration of GHG emission performance standards into procurement policies. We identified Phase 1 of this rulemaking as the forum for considering the following threshold issues:[29]

(a) Should the Commission adopt an interim GHG emissions performance standard to guide electric procurement decisions while it takes the necessary steps to fully implement D.06-02-032?

(b) If the Commission elects to adopt such a standard, how should it be designed and implemented so that it can be put in place quickly to serve this purpose.

The Assigned Commissioner proceeded to solicit pre-workshop comments on these issues, and staff of the Division of Strategic Planning ("staff" or "Commission staff") held a three-day workshop on June 21-23, 2006 to obtain further input from interested parties before formulating preliminary recommendations to the Commission.[30] Over 80 individuals, representing

[28] D.06-02-032, *mimeo*., p. 16.

[29] *Assigned Commissioner's Ruling: Phase 1 Scoping Memo and Notice of Workshop on Interim Greenhouse Gas Emissions Performance Standard*, June 1, 2006. (June 1, 2006 ACR)

[30] The workshop was facilitated by Richard Cowart from the Regulatory Assistance Project, as a consultant to the Division of Strategic Planning.

approximately 50 different stakeholders, attended one or more days of the workshop. Staff's preliminary recommendations were presented in the *Draft Workshop Report: Interim Emissions Performance Standard Program Framework* ("draft report"), which was issued for comment on August 21, 2006.

On September 29, 2006, Governor Schwarzenegger signed SB 1368 into law. Among other things, SB 1368 directs this Commission to establish a GHG emission performance standard through a rulemaking proceeding by February 1, 2007. It also specifies certain design elements of the GHG performance standard and associated definitions. The full text of SB 1368 is presented in Attachment 3.

Taking into consideration parties' comments on the draft report as well as the newly enacted provisions of SB 1368, staff issued its Phase 1 recommendations in the *Final Workshop Report: Interim Emissions Performance Standard Program Framework* ("final report") on October 2, 2006.[31]

On October 5, 2006, we designated this rulemaking as the procedural forum for implementing SB 1368. The Commission also amended the list of respondents in order to encompass a broader group of LSEs, consistent with the definition of that term in SB 1368.[32] On that same day, the Assigned Commissioner amended the Phase 1 scoping memo to reflect these changes. The Phase 1 comment period was also extended to provide opportunity for respondents and interested parties to file written comments/legal briefs on all

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[31] Staff's draft and final reports, along with other workshop-related materials are posted on the Commission's website at http://www.cpuc.ca.gov/static/energy/electric/climate+change.

[32] See *Order Amending Order Instituting Rulemaking*, October 5, 2006.

Phase 1 issues in the context of SB 1368, prior to our issuance of a draft decision.[33] Over thirty-five parties submitted one or more sets of written comments or legal briefs during Phase 1. Attachment 4 lists the organizations that jointly or individually filed legal briefs, pre-workshop, post-workshop and/or final comments in Phase 1.

As required by SB 1368, we have consulted with the California Independent System Operator (ISO), CARB and CEC in designing the interim GHG emissions performance standard.[34] Consistent with our intent to work collaboratively with these agencies in this rulemaking, Commission staff and the assigned Administrative Law Judge (ALJ) met informally with staff from the CEC, CARB and the California ISO in order to brief them on the content of the staff recommendations, controversial issues raised in comments from the parties, and likely resolution of these issues in this decision. Commission staff also sought feedback during these meetings from collaborative agency staff. These meetings took place in October and November 2006, and additional consultation may occur prior to final adoption of the EPS in the form of informal meetings or written exchange.

3. Context and Policy Objectives

As discussed above, the Commission's GHG Policy Statement provided the Commission's initial policy context for consideration of an EPS in this rulemaking, while SB 1368 now also provides the statutory context. The

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[33] *Assigned Commissioner's Ruling: Phase 1 Amended Scoping Memo and Request for Comments on Final Staff Recommendations,* October 5, 2006. (October 5, 2006 ACR.)

[34] § 8341 (d)(1) and (6).

principles and objectives articulated in each are nearly identical.[35] Both observe that California will need to rely on clean and efficient fossil-fired generation to the extent that energy efficiency and renewable resources are unable to satisfy increasing energy and capacity needs, consistent with the policies of the Energy Action Plan (EAP).[36] In addition, the Commission's GHG Policy Statement and SB 1368 recognize that:

(1) California's investor-owned utilities are currently making new long-term financial commitments to electrical generating resources that will have major impacts on GHG emissions for many years to come.

(2) It is vital to reduce California's exposure to costs associated with future federal regulation of GHG emissions.

(3) A GHG emissions performance standard for new long-term financial commitments to electrical generating resources will reduce potential financial risk to California consumers for future pollution-control costs.

(4) A GHG emissions performance standard for new long-term financial commitments to electric generating resources will reduce potential exposure of California consumers to future reliability problems in electricity supplies.

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[35] See GHG Policy Statement, pp. 1-2 and SB 1368, Section 1, (a)-(l).

[36] The EAP adopted in May 2003 (and augmented by the October 2005 EAP II implementation roadmap) sets forth a blueprint for achieving the state's overall goal of adequate, reliable, and reasonably priced electrical power and natural gas supplies. Among other things, the EAP identifies the following "loading order" of energy resources that guides decisions made by this Commission and the CEC: (1) conservation and energy efficiency first, in order to minimize increases in electricity and natural gas demand, (2) renewables and distributed generation second, in recognition that new generation is both desirable and necessary, and lastly (3) clean and efficient fossil generation to the extent that (1) and (2) are not sufficient to meet California's energy needs.

(5) The establishment of a policy to reduce emissions of greenhouse gases, including an emissions performance standard for all procurement of electricity by LSEs, is a logical and necessary next step to meet the goals of the EAP and the Governor's goals for reduction of emissions of greenhouse gases, and

(6) As the largest electricity consumer in the region, California has an obligation to provide clear guidance on performance standards for procurement of electricity by LSEs.

As articulated above, the primary objective of an EPS is to reduce California's exposure to the compliance costs associated with future GHG emissions (state and federal) and associated future reliability problems in electricity supplies. To meet this objective, an EPS functions similar to an appliance efficiency standard by ensuring that an LSE does not enter into long-term financial commitments with high-emitting baseload resources in the first place. For example, if a consumer wants to purchase a new refrigerator in California, he or she has a variety of models to choose from--each with a different upfront purchase price, operating efficiencies and associated costs per kWh to run, and other design attributes. However, at a minimum, each refrigerator must meet the threshold for appliance efficiency established by the standard. Similarly, SB 1368 establishes a minimum threshold of performance for any baseload generation facility that represents a new long-term financial commitment entered into by entities providing power to California ratepayers.

Some parties argue that our current oversight of utility resource planning is sufficient to achieve the Commission's procurement objectives, and therefore an EPS is not needed. In particular, San Diego Gas & Electric Company and Southern California Gas Company (SDG&E/SoCalGas) argue that the EAP "loading order" priorities and RPS program requirements render an interim EPS unnecessary.[37] We disagree. While loading order priorities and RPS requirements may reduce the overall size of the procurement needs to be filled by fossil-fired baseload generation, they do not establish safeguards against the risks associated with long-term procurement commitments to high GHG-emitting fossil-fired generation facilities. In fact, the EPS specifically addresses the last critical element of the EAP loading order, which prioritizes clean, efficient fossil generation.

Nor does the use of a GHG adder in the utility procurement process serve to adequately protect California ratepayers from these risks, as some parties suggest. The GHG adder, which assigns a $/ton cost to GHG emissions, is used to reflect one factor among many for utility competitive procurement—and not as a regulatory standard. The use of the GHG adder can still result in a significant number of new long-term financial commitments with powerplants emitting GHGs that far exceed the EPS—an outcome that this Commission and the Legislature recognize would pose substantial financial and reliability risk to California ratepayers.[38] In contrast, the interim EPS sends clear direction that

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[37] *Post-Workshop Comments of SDG&E/SoCalGas, June 27, 2006, p. 2.* See the footnote above for a description of the EAP loading order. In addition, by law, electricity production from eligible renewable energy resources must equal at least 20% of the total electricity sold to retail customers in California per year by December 31, 2010. (SB 107, Stats. 2006, ch. 464.) The RPS program was established by this Commission to implement these requirements, and RPS-related issues are addressed in R.06-02-012 and R.06-05-027.

[38] This can occur under the following type (or combination) of circumstances: (1) the level of upfront investment costs or power purchase contract prices associated with a high GHG-emitting powerplant are low relative to the discounted stream of emission-related costs captured by the $/ton GHG adder, (2) the operating and fuel costs of the

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California has "raised the bar" for the GHG emissions performance of new long-term commitments with baseload generation serving California as we transition to a statewide, load-based GHG emissions cap.

It is within this context that we turn to the specific design and implementation of an interim EPS. As discussed in the Assigned Commissioner's scoping memo, our focus today is to adopt an interim standard that will serve as a near-term bridge to the load-based GHG cap adopted under the Commission's Procurement Incentive Framework.[39] This focus is consistent with SB 1368, which directs the Commission to "reevaluate and continue, modify, or replace" the GHG performance standard adopted pursuant to the new law when "an enforceable" GHG emissions limit is established and in operation that is applicable to LSEs.[40] Consistent with the provisions of SB 1368, we will reevaluate the interim standard through a rulemaking proceeding and in consultation with the CEC and CARB.

Therefore, today's decision focuses on the most appropriate design parameters for an interim EPS, rather than a permanent one. SB 1368 also

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high GHG-emitting powerplant are significantly lower than those of an EPS-compliant alternative, and/or (3) the upfront costs or power purchase prices associated with an EPS-compliant alternative are significantly higher than those of the high GHG-emitting powerplant, even if the operating or fuel costs are relatively low. There is no way to ensure through the use of a $/ton GHG adder (even one that is higher than the current level) that all long-term commitments to baseload generation facilities that emit above a certain performance threshold will be precluded, since each calculation will depend on variables unique to the type of alternatives analyzed and on assumptions that may vary significantly over time (e.g., fuel prices, construction costs, contract prices or discount rates).

[39] June 1, 2006 ACR, p.1.

[40] § 8341(g).

requires that the standard be established no later than February 1, 2007 and be enforced immediately upon its establishment.[41] Accordingly, we will consider the various Phase 1 proposals in the context of this implementation timeframe.

Our overall objective is to design an interim performance standard that focuses on new long-term financial commitments to electrical generating resources that will have major impacts on GHG emissions for many years to come. This enables us to prevent major LSE procurement "backsliding" that will make future GHG reductions more difficult. In this way, we can accomplish the key objective for the EPS, namely, to minimize the risk of new financial commitments that pose the greatest risk of raising future compliance costs to ratepayers and of causing future reliability disruptions in electricity supplies.[42] We also seek to develop an EPS that is relatively simple to administer and implement, and that will keep the analysis and application of the standard to various resources transparent.

4. Interim GHG Emissions Performance Standard: Design and Implementation

In the discussion that follows, we use the terms "interim GHG emissions performance standard," "standard," and "emissions performance standard" (or "EPS") interchangeably. We use the term "greenhouse gases" or "GHG" to refer to the types of emissions that will ultimately need to be included in the strategies to mitigate climate change. More specifically, this term refers to the six gases listed under Section 42801.1(h) of the California Health and Safety Code: (1) carbon dioxide (CO_2), (2) methane, (3) nitrous oxide, (4) hydrofluorocarbons,

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[41] § 8341(d).

[42] See Section 1 of SB 1368, subsections (i) and (j).

(5) perfluorocarbons, and (6) sulfur hexafluoride, consistent with the definition contained in SB 1368.[43]

While the new law refers to all six of the gases listed above in its definition of greenhouse gases, it also establishes a deadline of February 1, 2007 for enforcement of the EPS. We do not have sufficient data to create and enforce a GHG emissions performance standard beginning February 1, 2007 that covers all of the gases. Currently, utility data for the CCGT standard contemplated by SB 1368 is only reported to the California Climate Action Registry for the largest GHG emissions source by volume, namely, for CO_2. This is also the only GHG consistently reported by electrical corporations on an entity-wide basis at this time.[44] The Commission will seek to identify options to integrate reporting of all GHGs in the future. However, in order to meet the February 1, 2007 statutory deadline, we limit today's adopted EPS to CO_2 emissions as it is the most pervasive of the GHGs, and the most widely reported and verified of the GHGs at this time.

We may reevaluate how the EPS can be expanded to include some or all of the additional gases listed above when sufficient knowledge and data becomes available on their respective emission levels from generation sources, and when that information can be translated into an enforceable EPS.[45]

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[43] § 8340(g).

[44] In particular, as part of the California Climate Action Registry, Pacific Gas and Electric Company (PG&E) has only started to report the other gases beginning in 2006, and SDG&E and Southern California Edison Company (SCE) will start reporting them beginning in 2007.

[45] As discussed in Section 4.10 below, we consider representative emissions of both methane and CO_2 for a much more limited purpose, namely to show that generating electricity from biomass, biogas or landfill energy can actually *reduce* the net GHG

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SB 1368 specifies several design and implementation parameters for the interim EPS, and in the following sections we highlight the relevant language from the statute. For each design or implementation issue, we briefly summarize the staff proposal as well as the chief points of contention reflected in parties' comments before presenting our conclusions. As usual in such proceedings, the record is voluminous, and therefore we do not summarize every nuance in individual positions.

4.1. Entities Subject to the EPS

Prior to the passage of SB 1368, there was some debate on both policy and legal grounds as to which entities should be subject to the EPS. All parties now conclude, as we do, that SB 1368 has laid this debate to rest by directing that this Commission develop an EPS for LSEs and by specifically defining that term in the new law. Consistent with that definition, the EPS we adopt today will apply to every electrical corporation, electric service provider, or community choice aggregator serving end-use customers in the state.[46] Throughout this decision, we use the term "LSE" to refer collectively to these entities.

4.2. Types of Generation and Financial Commitments Subject to the EPS ("Covered Procurements")

SB 1368 describes what types of generation and financial commitments will be subject to the EPS ("covered procurements"). Under SB 1368, the EPS applies to baseload generation, but the requirement to comply with it is triggered

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emissions associated with the disposal of society's waste and residue materials, and therefore we should pre-approve biomass generation as complying with the EPS.

only if there is a "long-term financial commitment" by an LSE.[47] There are two kinds of "long-term financial commitments" under SB 1368. For LSE-owned powerplants a long-term financial commitment occurs when there is a "new ownership investment." For baseload generation procured under contract, there is a "long-term financial commitment" when the LSE enters into "a new or renewed contract with a term of five or more years."[48] For purposes of our discussion here, we will call a long-term financial commitment for baseload generation a "covered procurement."

SB 1368 defines baseload generation as "electricity generation from a powerplant that is designed and intended to provide electricity at an annualized plant capacity factor of at least 60 percent."[49] The new law defines the terms "powerplant" and "plant capacity factor" for this purpose, as follows:[50]

- "Powerplant" means a facility for the generation of electricity, and includes one or more generating units at the same location.
- "Plant capacity factor" means the ratio of the electricity produced during a given time period, measured in kilowatt hours to the electricity the unit could have produced if it had been operated at its rated capacity during that period, expressed in kilowatt hours.

Finally, the statute also states that "all combined-cycle natural gas powerplants that are in operation, or that have an Energy Commission final

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[46] § 8340(c), (d), (e), and (h). To date, no community choice aggregator has been formed, though interest has been expressed in a number of localities.

[47] § 8341(a), first sentence.

[48] § 8340(j).

[49] § 8340(a).

[50] § 8340 (m) and (l), respectively.

permit decision to operate as of June 30, 2007, shall be deemed to be in compliance" with the EPS.[51]

In the following sections we discuss the issues raised in parties' comments with respect to covered procurements.

4.2.1. Capacity Factor of Covered Procurements

In their comments, Green Power Institute (GPI) recommends that the EPS be applied to generation from facilities with an annual plant capacity factor of at least 50 percent, rather than the 60 percent capacity factor directed by SB 1368. To do as GPI suggests would directly contradict the plain language of the statute. Accordingly, the interim EPS will apply to baseload generation as that term is defined in SB 1368. We note that staff and most parties to this proceeding recommended a 60% capacity factor, even prior to the passage of SB 1368, based on the data submitted in Phase 1 of this proceeding. That data illustrates that a 60% capacity factor captures an estimated 78% of the incremental procurement needs in 2012 for PG&E, SDG&E and SCE combined, and would capture 72% of CO_2 emissions associated with those procurement needs.[52]

4.2.2. Renewal Contracts

Prior to the passage of SB 1368, parties were divided on the issue of whether contract renewals with existing baseload generating facilities should be

[51] § 8341(d)(1).

[52] These figures represent the percentage of annual CO_2 associated with the utilities' incremental procurement needs in 2012 that would be captured by new commitments to facilities operating at a 60% capacity factor (based on heat rates in the 7000-8600 range). See Response #3 to the ALJ's June 21, 2006 data request posted at www.cpuc.ca.gov/static/energy/electric/climate+change.

subject to the EPS. The language of the statute is clear that new as well as renewal contracts having a term of five years or more represent a "new financial commitment," and therefore must comply with the EPS. Accordingly, we adopt the definition of new financial commitment contained in SB 1368 for the interim EPS.

4.2.3. Retained Baseload Generation

Retained baseload generation refers to the existing baseload facilities (e.g., coal, nuclear or natural gas-fired plants) owned by the LSE and used to serve its load. As several parties note in their comments, under staff's proposal, retained baseload generation does not enter into the type of commitments that would trigger the EPS review, unless the LSE makes major plant renovations or sells that power under a contract of five years or more with another LSE. Two major questions were raised by parties with respect to retained baseload generation:

(1) Should the LSE's retained baseload facilities be subject to the EPS as a general principle—irrespective of whether the LSE makes a new financial investment in the plant?

(2) Should the utility's new investments (plant alterations) to retained baseload generation trigger application of the EPS, and if so, what types of plant alterations?

We discuss each of these issues below.

4.2.3.1. Retained Generation Without New Utility Investment

Constellation Energy Group (Constellation), Alliance for Retail Energy Markets (AReM) and a number of individual electric service providers propose that the Commission develop a mechanism to subject all of the utility's retained baseload generation to the EPS, either immediately upon implementation of the

EPS or periodically thereafter.[53] These parties contend that not doing so creates a *de facto* loophole in the establishment of an EPS, which violates the goals and statutory language of SB 1368.

In particular, Constellation et al.[54] argue that the reference in § 8341(d)(1) to "all baseload generation of load-serving entities" precludes any disparate treatment for utility-owned generation and non-utility owned generation. They believe that such disparate treatment exists if the EPS is triggered for all contracts of five years or longer with non-utility owned existing baseload generation (with or without major renovations), but only for utility-owned existing baseload generation if and when it undergoes major renovations. Accordingly, they recommend that the Commission require the utilities to demonstrate compliance with the EPS upon renewal of any "rate recovery contract" for its retained baseload generation, meaning any time the utility seeks rate modifications or submits procurement plans supporting existing utility-owned assets.

Constellation et al.'s reading of the statute is incorrect. As discussed above, the plain language of SB 1368 provides clear direction as to what triggers the requirement to apply the EPS: Sections 8341(a), (b)(1), and (b)(2) provide that the EPS shall apply to all baseload generation *in the event that the compliance requirement is triggered by a "long-term financial commitment"* as defined in

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[53] AReM's membership includes a number of electric service provider respondents in this proceeding: APS Energy Services Company, Inc.; Commerce Energy, Inc.; Constellation Newenergy, Inc.; Sempra Energy Solutions; and Strategic Energy, LLC.

[54] See *Joint Comments of Constellation Newenergy, Inc., Constellation Energy Commodities Group, Inc., Constellation Generation Group, LLC, NRC Energy, Inc., Mirant California, LLC,*

Footnote continued on next page

§ 8340(j). And that subsection contains an asymmetric definition of what constitutes a "long-term financial commitment" for utility-owned generation and contracted-for generation.

In their comments, Constellation et al. take the phrase "all baseload generation of load-serving entities" in § 8341(d)(1) out of context with respect to the rest of the statute. In particular, that phrase is used in the context of the Legislature's direction for when ("on or before February 1, 2007") the Commission must establish and EPS and at what rate of emissions ("no higher than the rate of emissions of greenhouse gases for combined-cycle natural gas baseload generation."). To interpret this phrase to mean that the Legislature intended to subject utility-owned retained baseload generation to the EPS, with or without a "new ownership investment" as required by § 8341(a)(1), would contradict the language of §§ 8341(a), (b)(1), (b)(2) and § 8340(j), or render it meaningless.

Moreover, the only way to give the meaning to § 8340(j) that Constellation et al. suggest would be to assume, as these parties do, that a "renewed contract" under the definition of "long-term financial commitment" in § 8340(j) includes the type of "rate recovery contract" with existing utility-owned baseload generation facilities that these parties describe in their comments. First of all, it is doubtful that the kinds of regulatory measures that Constellation et al. describe are contracts as that term is ordinarily understood. Even if they are "contracts," they are not the kind of contracts the Legislature was describing in § 8340(j). Contracts for the procurement of baseload generation and "contracts" for the

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Mirant Delta, LLC, Mirant Potrero, LLC and Alliance for Retail Energy Markets on Final Workshop Report, October 18, 2006, p. 7.

recovery of costs associated with generation are two separate things. The statute clearly only applies to the former. Furthermore, Constellation et. al. do not suggest how one would determine whether any particular "rate recovery contract" is for a period of less or more than five years.

Nothing in the statutory language or legislative history reflects this intent or direction.[55] In fact, in the Senate Committee analyses of SB 1368 the term "long term contract" is consistently referred to in the context of the procurement contracts covered under the Commission's procurement planning process, which do not apply to utility-retained generation.[56]

Finally, contrary to Constellation et al.'s assertions, we believe that excluding utility-owned retained generation from EPS-covered procurements (unless the electricity sold to another LSE under a long-term contract or the powerplant is renovated as that term is defined in this decision) is fully consistent with the principles and objectives for an interim EPS articulated by the Legislature and this Commission. As discussed in Section 3 above, both the Legislature and this Commission have recognized that California utilities are "currently making new long-term financial commitments to electrical generating resources that will have major impacts on GHG emissions for many years to come," and have concluded that an EPS "for new long-term financial commitments to electrical generating resources will reduce potential financial

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[55] Throughout this decision, our references to "legislative history" refer to the history of the bill as it was amended in the Legislature, the Committee Analyses at each reading (available at www.leginfo.ca.gov), as well as the public Committee hearing tapes available on SB 1368, all of which we have carefully reviewed.

[56] See, for example, Senate Third Reading on SB 1368 (as Amended August 21, 2006 and as amended August 30, 206), p. F: *"What is a long-term contract?*."

risk to California consumers for future pollution-control costs."[57] Accordingly, the definition of covered procurements that we adopt today focuses on preventing "backsliding" through new LSE procurement decisions that will make future GHG reductions more difficult.

Constellation et al. fundamentally disagree with these stated objectives for an EPS. Rather than focus on new financial commitments, they recommend that the EPS scope be broadened to apply to the LSE's existing fleet of baseload generation facilities that are used to meet the LSE's load. However, this is not the purpose of the EPS, as discussed above. In effect, the definition that Constellation et al. recommend would subject the millions of dollars in the LSE's already-built facilities to a standard that is being developed to prevent backsliding in LSE decisions made for future investments and avoid the additional financial and reliability risks that such backsliding would create.

For the above reasons, we reject this recommendation. We will adopt what the Legislature intended by using the same definitions for covered procurements as in the statute. As discussed above, § 8340(g) defines "long-term financial commitment" as "either a new ownership investment in baseload generation or a new or renewed contract with a term of five or more years, which includes procurement of baseload generation."

4.2.3.2. Retained Generation With New Utility Investment

SCE interprets SB 1368 to exclude from EPS review any new utility investment in retained generation. Specifically, in its comments on the draft report, SCE argues that the definition of "long term financial commitment"

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[57] See GHG Policy Statement, pp. 1-2 and SB 1368, Section 1, (a)-(l).

provided by SB 1368 is limited to an "'investment in baseload generation' that is also a 'new ownership' interest."[58] To support this reading SCE argues that the absence of a comma between "new" and "ownership" necessarily means that "new" modifies "ownership" and not "investment." Under SCE's reading, therefore, an investment in baseload generation that is part of an "existing ownership interest," such as repowering or otherwise renovating utility retained generation, would not have to comply with the EPS. SCE bases its grammatical argument on rules outlined in *The Gregg Reference Manual*.

SCE's assertion that the absence of a comma mandates their reading is incorrect. According to several other sources of grammatical usage, including *The Chicago Manual of Style* and *The Random House Handbook*, a comma should be inserted between adjectives when they both modify the same noun in the exact same way.[59] Thus, the phrase "nutritious, delicious dinner" has a comma in it, because both "nutritious" and "delicious" modify the word "dinner." Where a comma is required, the two adjectives "can be reversed without affecting their meaning"[60] Thus, a "nutritious, delicious dinner" is readily understood to mean the same thing as a "delicious, nutritious dinner."

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58 *Reply Comments of SCE on the Draft Workshop* Report, September 15, 2006, p. 4. In their comments SCE equates the word "investment" from the statute with the word "interest." Had the Legislature used the word "interest" instead of "investment" it would support SCE's reading. The Legislature, however, chose to use "investment" and not "interest," and therefore did not limit the application of the EPS to new ownership investments that *also* represent a new ownership interest.

59 Bergen Evans, *A Dictionary of Contemporary American Usage*, Random House (New York, © 1957)

60 Frederick Crews, *Random House Handbook*, 4th Ed. Random House (New York, © 1984).

Accordingly, a comma would only be necessary if one could substitute the phrase "ownership, new investment" for the phrase "new, ownership investment" without affecting the meaning. However, changing the order of the words does affect the meaning; indeed it is not easy to comprehend what the phrase "ownership, new investment" would mean if it had appeared in the statute. Furthermore, these authorities establish that no comma is required where the first adjective modifies the idea expressed by the combination of the second adjective and the noun.[61] In these cases, the second adjective pairs with the noun, and the two together are then modified by the first adjective. Thus, no comma is required when we talk about the "typical American meal" or "traditional political institutions." In the first instance the word "typical" modifies the phrase "American meal"; in the second, "traditional" modifies "political institutions." Similarly, here the word "new" modifies the phrase "ownership investment" and no comma is required to express that meaning. Therefore, SCE's argument here is simply wrong.

In its comments on the final report, SCE adds several more arguments contending that SB 1368's definition of "long-term financial commitments" should be read to exclude significant renovations or repowering of utility retained generation. In particular, SCE argues that "the purpose of SB 1368 is to encourage new long-term financial commitments to zero- and low-carbon generating resources – not to prohibit other long-term financial commitments,

[61] *The Chicago Manual of Style*, 14th Ed., The University of Chicago Press (Chicago, © 1993).

such as major renovations in existing facilities as staff would do."[62] In support of this argument SCE cites SB 1368 § 1(e) which states that "new long-term financial commitments to zero- or low-carbon generating resources should be encouraged."

We read this statement of intent to apply most directly to § 8341(b)(6), which provides for an increased return on investment for third parties selling "zero- or low-carbon generation" to electrical corporations. Not only does SCE misunderstand that "encourage" as it appears in SB 1368 specifically refers to § 8341(b)(6), but SCE also ignores the fact that the statute explicitly prohibits "load-serving entities from entering into long-term financial commitments unless any baseload generation" supplied under that commitment complies with the EPS established by the commission. [§ 8341(a).] Thus, SCE's reading is contrary to the plain language of the statute, since § 8341(a) clearly *prohibits* LSE's from entering into long-term financial commitments that fail to comply with the EPS.

SCE next contends that the legislative history supports its view that "SB 1368 does not apply to major renovations of exiting facilities where the ownership of the facility has not changed."[63] As SCE notes, on June 22, 2006 the definition of "long-term financial commitment" was amended and the word "new" was inserted in front of "ownership investment." SCE argues that this change clearly demonstrates the Legislature's intent to include only "new ownership investments," as in acquisitions, and to exclude "existing ownership investments," as in renovations or repowering of utility retained generation.

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[62] *Opening Comments of SCE on Final Staff Workshop Report,* October 18, 2006, p. 3, emphasis in the original.

[63] *Ibid*., p. 5.

We disagree. Before "new" was added to the definition, "ownership investment" could have been read to include *all* utility retained generation, including those facilities built, repowered and renovated prior to the statute's effective date. This is because "investment" can mean either: the sum which is currently invested; or, the placing or outlay of money for income or profit.[64] Both meanings are commonly used, and we must assume that the Legislature was aware of this potential ambiguity. Absent the word "new" it is unclear as to whether "ownership investment" means: 1) the sum which is currently invested, as in all utility retained generation; or 2) the outlay of money for baseload generation, as in new commitments of money such as repowering and other major renovations to existing facilities. We conclude that the Legislature added "new" to preclude the broader interpretation that would include all utility retained generation and not, as SCE contends to exclude new investments in utility retained generation.

In sum, we concur with staff, Natural Resources Defense Council (NRDC), The Utility Reform Network (TURN), Union of Concerned Scientists (UCS), Western Resource Advocates (WRA) and others that the term "new ownership investment" under SB 1368 encompasses new LSE investments in retained baseload generation.

Several suggestions were presented in comments regarding when the EPS would be triggered for such new ownership investments. Under the staff proposal, repowering of an existing baseload facility would trigger the application of the EPS, in addition to other new financial commitments to

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[64] *Merriam-Webster's Collegiate Dictionary*, 10th Ed. (2001), p. 615

baseload plant.[65] California Cogeneration Council (CCC) would add that LSE-owned generation be subject to the EPS whenever major equipment is replaced or added, and defines "added" to include the installation of air pollution control equipment. PG&E and SDG&E/SoCalGas recommend that the EPS be triggered for current retained generation (or once a new plant has demonstrated compliance with the EPS) only if the powerplant is repowered or upgraded in such a way that its design capacity has increased.[66]

In their joint comments on the draft report, NRDC, TURN, UCS and WRA recommend that the Commission consider all major refurbishments, in addition to repowering, to represent new ownership investments that would be subject to the standard. In determining what constitutes a major refurbishment, these parties recommend that the Commission set a threshold for the EPS based on total dollars and total greenhouse gas emissions at stake, but do not propose specific levels for this threshold. More generally, they suggest that the refurbishment be subject to the EPS if it is intended to extend plant life by more than five years and if the plant is designed and intended to operate at a 60 percent capacity factor or greater.

Among these suggestions, we are looking for the best and most workable approach to identifying changes in an existing powerplant that would increase

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[65] Repowering generally refers to the construction of new generating units at an existing site and the complete or partial dismantling of existing generation units at the same site. Existing units are not always entirely retired or dismantled. Generators can often re-use the busbar/transformer arrays, transmission tap lines to grid interconnect, water and gas supply lines and cooling structures during repowering.

[66] *Opening Comments of PG&E on Draft Workshop Report*, September 8, 2006, p. 5. *Reply Comments of SDG&E/SoCalGas on Draft Workshop Report*, September 15, 2006, pp. 4-5.

the expected level of GHG emissions from the facility over the long-term. This is not accomplished by requiring that any replacement of equipment or addition of pollution control equipment should trigger the EPS, as CCC suggests. Even after such changes, the plant and its operation may remain essentially unchanged. More importantly, this approach could reduce reliability as old parts are repaired rather than replaced.

We also believe it would be arbitrary to try to set a dollar level threshold for new ownership investments, as NRDC and others recommend. However, their suggestion that the EPS be triggered by refurbishments that significantly extend the plant life does have merit. When coupled with the proposal by PG&E, SDG&E and SoCalGas, we think a workable definition of new ownership investments can be crafted.

Specifically, in addition to new baseload plant construction or the acquisition of new ownership interest in an existing plant owned by others, we will define "new ownership investments" to include any investment that is intended to extend the life of one or more units of an existing baseload powerplant for five years or more, or results in a net increase in the existing rated capacity of that powerplant. "Rated capacity" refers to the nameplate capacity of the plant, i.e., the plant's maximum rated output under specific conditions designated by the manufacturer and usually indicated on a nameplate physically attached to the generator. New ownership investments will also include any investment made for the purpose of converting a non-baseload plant to a baseload plant (i.e., so that it is now designed and intended to provide electricity at an annualized plant capacity factor of 60 percent or greater).

We believe that the definition above covers "repowering" as the term is generally used in the industry, since the types of renovations normally undertaken during repowering (e.g., replacing one or more of the plant's existing turbine(s)) would significantly extend the life of the unit(s), increase the rated capacity of the powerplant, or both. However, only those units in a multi-unit generating facility that are being added, replaced or altered must comply with the EPS.[67]

4.2.4. "Deemed-Compliant" Combined Cycle Natural Gas Powerplants

This brings us to the issue raised by staff's final recommendations, namely, the treatment of combined cycle natural gas powerplants deemed to be in compliance under § 8341(d)(1). We use the term "combined cycle gas turbine" (or "CCGT") powerplant to refer to a "combined cycle natural gas plant" defined in SB 1368.[68]

SB 1368 provides that all CCGT powerplants "that are in operation, or that have an Energy Commission final permit decision to operate as of June 30, 2007, shall be deemed to be in compliance with the greenhouse gases emission performance standard."[69] Staff recommends that a powerplant deemed compliant pursuant to § 8341(d)(1) ("deemed-compliant CCGT powerplant") be required to demonstrate actual compliance upon repowering or upon the

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[67] At the request of the assigned ALJ, interested parties commented on this definition in their October 27, 2006 reply comments. We note that those comments indicate general concurrence with the definition presented above.

[68] Specifically, a CCGT powerplant refers to a powerplant that "employs a combination of one or more gas turbines and steam turbines in which electricity is produced in the steam turbine from otherwise lost waste heat exiting from one or more of the gas turbines." (§ 8340(b).)

[69] § 8341(d)(1). We conclude that the Legislature intended that the concept of "deemed compliance" be distinct from the concept of "compliance" generally. (Hereinafter, we will use the terms, "actual compliance" and "compliance" interchangeably).

renewal of a power purchase contract of five years or more. PG&E, SDG&E/SoCalGas and others argue that this recommendation is inconsistent with the statutory language described above that essentially "grandfathers" these plants, thereby exempting them from the requirement to demonstrate compliance with the EPS.

The staff proposal would essentially apply the same standard of review for deemed compliant CCGT plants as for all other existing plants.[70] As discussed in Section 4.2.3.2, SB 1368 requires that an LSE demonstrate compliance for all "new ownership investment" in retained generation, which we define as alterations intended to extend the life of one or more units of an existing baseload powerplant for five years or more, or result in a net increase in the existing rated capacity of the powerplant.

A CCGT powerplant that is *deemed* compliant does not have to demonstrate actual compliance with the adopted EPS standard, but is instead treated *as if* it met the EPS standard and is excused from making an affirmative showing of compliance.[71] Reading § 8341(d)(1) to require that the same kind and scale of alterations, improvements, additions, or renovations that constitute "new ownership investment" would also trigger a requirement that deemed-

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[70] We find no indication in SB 1368, or in its legislative history, that the Legislature intended that CCGT powerplants, or any of the individual CCGT units such powerplants contain at the time they are deemed compliant, should lose their deemed-compliant status solely due to contract renewal. If the Legislature had intended to require that existing facilities demonstrate actual compliance upon contract renewal, instead of deeming the CCGT facilities themselves compliant, they could have stated so explicitly.

[71] The verb "deem" means "to treat something as if (1) it were really something else, or (2) it has qualities it doesn't have". *Black's Law Dictionary*, 7th Ed, at 424, West Publishing (St. Paul, Minnesota © 1999.)

compliant CCGT powerplants demonstrate actual compliance with the EPS, would render the § 8341(d)(1) deemed-compliant provision redundant as applied to utility-owned CCGT powerplants.

California courts have long observed the canon of statutory construction that when attempting to ascertain the meaning of a statute, "effect should be given…to the statute as a whole and to every word and clause thereof, leaving no part of the provision useless or deprived of meaning."[72] In order to give § 8340(j), (defining long term financial commitment to include new ownership investments), § 8341 (requiring that all long term financial commitments meet the EPS) and § 8341(d)(1) (deeming CCGTs compliant) their full effect with respect to utility-owned CCGTs in operation as of the date of implementation of the EPS (or that obtain a CEC permit as of June 30, 2007), we conclude that "new ownership investment" in retained generation does not automatically trigger EPS review for deemed-compliant CCGT powerplants.

Another canon of statutory construction, however, requires us to avoid interpretations of law that would lead to an absurd result.[73] The purpose of SB 1368 would be thwarted if existing CCGT are deemed to be permanently in compliance regardless of any subsequent changes to the facilities. One could argue that if units are added to an existing deemed-compliant CCGT powerplant — thereby increasing its capacity from 50 MW to 250 MW — the additional units are nevertheless "deemed compliant" and do not have to demonstrate actual compliance. Under this construction, an LSE or non-LSE owner could circumvent the EPS simply by co-locating these additional units with existing

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[72] *Gay Law Students Association* v. *Pac. Tel. & Tel. Co.,* (1979) 24 Cal.3d 458, 478.

units within a previously deemed-compliant CCGT powerplant. We should avoid construing the statute to achieve this absurd result. The deemed-compliant status is given to existing CCGT plants, and extending the exemption to units that did not exist at the time of the passage of the statute is contrary to the purpose and the intent of the law.

Therefore, we require that when additional units are added to a deemed-compliant CCGT baseload powerplant resulting in an increase of 50 MW or more to the powerplant's rated capacity, those additional units must demonstrate compliance with the EPS. We select a 50 MW threshold because it is already used to mark the boundary between significant and minor changes in generating capacity for the purpose of triggering CEC powerplant permitting requirements under Public Resources Code § 25123.[74]

In this way, we avoid the absurd result of creating a loophole that would allow for the installation of an unlimited amount of new capacity at an existing CCGT powerplant without any demonstration that that new capacity complies with the EPS. On the other hand, by not requiring deemed-compliant CCGTs to demonstrate compliance with the EPS for repowering as it is defined within the context of "new ownership investments," we eliminate the redundancy that would otherwise exist between §§ 8340(j), 8341, and 8341(d)(1) with respect to

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[73] *Landrum* v. *Superior Ct. of LA County*, (1981) 30 Cal.3d 1, 9.

[74] By citing Public Resources Code § 25123 in this case we are not adopting the language of the statute generally, nor are we importing any of the case law, regulations, or CEC decisions that have been generated in the process of interpreting that section, or the 50 MW number specifically.

retained generation.[75] While the addition of new units resulting in an increase of 50 MW or more to a powerplant's rated capacity is certainly a "new ownership investment," as we define it above, it is a subset of all the possible activities that would constitute "new ownership investment." Thus, by limiting our reading of what parts of a CCGT powerplant are deemed compliant (to exclude additional units totaling 50 MW or more) we avoid redundancy and give each word of § 8341(d)(1) a legal effect distinct from the other provisions of the statute.

Furthermore, nothing in today's decision or in SB 1368 limits the Commission's existing authority to require that utility-owned, or contracted for, CCGT powerplants are properly maintained and are operated as cleanly and efficiently as possible. The Commission retains the right to address questions related to the maintenance and efficiency of CCGT powerplants including but not limited to, the emissions from these plants, in the investor-owned utility general rate cases, long-term procurement plans, or other appropriate proceedings.

Putting this within the context of the other provisions of SB 1368 and our discussion of covered procurements, this means that an LSE -owned CCGT baseload powerplant deemed compliant under § 8341(d)(1) must demonstrate compliance for any units that it adds to its CCGT powerplant which result in an increase of 50 MW or more to the plants capacity as it was rated on the day it

[75] In particular, under §§ 8340(j) and 8341, compliance with the EPS is triggered for LSE retained baseload generation only when there is a "new ownership investment" in those facilities. If we construed 8341(d)(1) to mean that the very same "new ownership investment" trigger that applies to LSE retained generation applies equally to LSE-owned "deemed-compliant" retained CCGT generation, there would be redundancy among these sections of the statute.

was deemed compliant The following example shows how we will prevent CCGTs from circumventing EPS compliance by piece-mealing additions of capacity: a deemed-compliant CCGT powerplant which adds 25 MW of capacity in 2008 and another 25 MW in 2010 will have to show actual EPS compliance for the additional capacity in 2010. The rated capacity of CCGTs for the purpose of establishing when the 50 MW addition is reached will be: 1) for all CCGT plants that are in operation on the effective date of this decision—the rated capacity of the plant that is operating, or 2) for all other CCGT plants (or additions to plants) that obtain a CEC final permit to operate as of June 30, 2007—the rated capacity authorized by the permit.

A LSE is also required to demonstrate compliance with the EPS for any new or renewal contract of five years or longer with any CCGT baseload powerplant deemed compliant under § 8341(d)(1) that added new units resulting in an increase of 50 MW or more to the powerplant's rated capacity, as defined above. However, the LSE need only demonstrate EPS compliance for those CCGT units that were added to the deemed-compliant powerplant after it was deemed compliant. Procurement contracts that exist at the time additional units are installed to a deemed-compliant CCGT powerplant (resulting in an increase of 50 MW or more) will not be required to demonstrate compliance until contract renewal.

In sum, consistent with the provisions of SB 1368, our adopted interim EPS will apply to:

(1) New ownership investments in baseload generation made by an LSE, defined as:

  (a) Investments in new baseload powerplant (new construction), or

(b) Acquisition of new or additional ownership interest in existing baseload powerplant previously owned by others, or

(c) New investments in the LSE's own existing, non-CCGT baseload powerplants that are:

(i) intended to extend the life of one or more units by five years or more,

(ii) result in a net increase in the rated capacity of the powerplant, or

(iii) intended to convert a non-baseload plant to a baseload plant, or

(d) Units added[76] to a deemed-compliant CCGT powerplant that result in an increase of 50 MW or more to the powerplant's rated capacity,[77] or

(2) New contract commitments (including renewal contracts)[78] of five years or greater by an LSE with:

(a) baseload generation facilities, unless those facilities represent deemed-compliant CCGT powerplants, or

(b) any deemed-compliant CCGT powerplant that added units resulting in an increase of 50 MW or more to the powerplant's rated capacity. (The contracting LSE need only show that the added units meet the EPS).

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[76] Only the additional units must demonstrate compliance with the EPS. "Additional" units refer to units that were not previously operating at that specific powerplant (including additional refurbished or used units previously operating at a different powerplant).

[77] For the purpose of establishing when there has been a 50 MW addition, the existing rated capacity will be determined as follows: 1) for all CCGT plants that are in operation on the effective date of this decision—the rated capacity of the plant that is operating, or 2) for all other plants (or additions to plants) that obtain a CEC final permit to operate by June 30, 2007—the rated capacity authorized by the permit.

[78] The term "contract" as it is used in SB 1368 is equivalent to the term "power purchase agreement" that we use in our electric procurement proceedings.

4.3. EPS Performance Level (Emissions Rate)

Section 8341(d)(1) directs the Commission to establish an EPS performance level that is "no higher" than the rate of GHG emissions of a CCGT baseload powerplant. In that same section, SB 1368 includes the grandfathering provisions discussed above, namely, that "all combined-cycle natural gas powerplants that are in operation, or that have an Energy Commission final permit decision to operate as of June 30, 2007, shall be deemed to be in compliance with the greenhouse gases emissions performance standard."

The statute does not specify the emissions rate of a CCGT that it to be used for the EPS performance level. At the direction of the assigned ALJ, parties presented data on heat rates and emission factors for different types and vintages of CCGT powerplants and other generation technologies.[79] Parties were directed to specifically consider this data in presenting their proposals for the EPS performance level.

The initial staff "straw proposal" presented during workshops recommended a dual standard—one for existing resources (at a higher emissions rate) and one for new resources (at a lower one). In its draft report, staff modified this proposal and recommended instead a single EPS emissions rate of 1,000 lbs of CO_2/MWh (or "lbs/MWh"). After further consideration of the data, parties' comments and the provisions of SB 1368, staff now recommends that a single EPS emissions rate be established at 1,100 lbs/MWh. As discussed above, staff also recommends in the final report that existing CCGT's "deemed

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[79] Responses to the ALJ's request are posted at the Commission's website at www.cpuc.ca.gov/static/energy/electric/climate+change.

compliant" under § 8341(d)(1) be required to demonstrate compliance when repowered or upon contract renewal.

Independent Energy Producers Association (IEP), GPI, PG&E, SCE, SDG&E/SoCalGas (filing jointly), Energy Producers and Users Coalition and Cogeneration Association of California (EPUC/CAC, filing jointly) among others support an EPS level of at least 1,100 lbs/ MWh for a variety of reasons, including:

- An EPS level of 1,100-1,200 lbs/MWh would accommodate different CCGT configurations, some of which may have higher heat rates in order to meet other (non-greenhouse gas) environmental objectives, such as a facility with dry cooling technology for purposes of minimizing water use, or efficiency. (PG&E, IEP, GPI)
- A lower level (e.g., 1,000 lbs/MWh) would not appropriately take into account intermediate units, including reciprocating engine units that will be needed for reliable operation of the grid. (PG&E)
- An EPS level of at least 1,100 lbs/MWh would ensure satisfaction of SB 1368's mandate that all CCGTs currently in operation be deemed compliant with the EPS. (SDG&E/SoCalGas).
- An EPS even higher than 1,100 lbs/MWh should be set in order to ensure that all existing gas-fired units, not just CCGTs, are available for procurement. (EPUC/CAC, Center for Energy and Economic Development (CEED).)[80]

[80] More generally, CEED objects to the staff proposed EPS of 1,100 lbs/MWh because at that level it would preclude power plants that use oil, coal, petroleum and coke-fueled resources. Although CEED does not propose a specific EPS level in its comments, the record indicates that the EPS would need to be on the order of 1,700-1,800 lbs/MWh in order for baseload generation using these resources to be able to meet the standard. However, CEED ignores that fact that selecting this higher EPS level would not produce the amount of GHG emissions reduction that the statute clearly intends, as evidenced by the selection of a CCGT-based standard.

Division of Ratepayer Advocates (DRA), Sempra Global (Sempra), Calpine Corporation (Calpine) and NRDC support an EPS level of no more than 1,000 lbs CO_2/MWh. They argue that there is no need, based on the data presented in this proceeding, to set the EPS level higher than 1,000 lbs CO_2/MWh, given that SB 1368 already deems all existing CCGTs to be in compliance. DRA, in particular, contends that it is unnecessary to raise the EPS to 1,100 lbs/MWh to accommodate the minor reduction in efficiency associated with dry cooling.

In considering this issue, we note that SDG&E/SoCalGas interpret § 8341 (d)(1) to mean that the Legislature intended for all deemed-compliant CCGTs to be able to demonstrate that they would pass the adopted standard. We disagree with this interpretation. As we point out in Section 4.2.4 above, the verb "deem" means "to treat something as if (1) it were really something else, or (2) it has qualities that it doesn't have."[81] This common definition, in conjunction with § 8341(d)(1)'s requirement that the Commission adopt an EPS that is no higher than the rate of emissions for CCGT baseload generation, indicates that the Legislature intended to allow the Commission to adopt a standard that some CCGT powerplants might not be capable of meeting. While many deemed-compliant CCGT powerplants will certainly also be capable of demonstrating "actual" compliance, some fraction of deemed-compliant CCGTs may not be capable of demonstrating compliance with the EPS if they were required to do so. Nonetheless, under the provisions of § 8341 (d)(1), they will be treated as if they had passed the standard. Therefore, we do not agree with SDG&E/SoCalGas' recommendation that we should establish the EPS level high

[81] Black's Law Dictionary, 7th Ed, at 424, West Publishing (St. Paul, Minnesota © 1999).

enough so that it could be met by all deemed-compliant CCGTS, if they were required to comply.

Nor do we agree with EPUC/CAC's suggestion that we establish the EPS level high enough to ensure that all gas-fired units would meet it. Had the Legislature intended for the EPS to reflect the GHG emissions rate associated with gas-fired units, not just CCGTs, it would have stated so explicitly. Instead, the Legislature selected combined-cycle, gas-fired power generation as the basis for the EPS. We must assume that in doing so, the Legislature recognized that CCGT technology is considered to be the "technology of choice" for new, baseload power generation fired by natural gas because of its efficiency advantages over other forms of gas-fired power generation.[82] Moreover, the Legislature specifically directed that the emissions rate be reflective of a "baseload" CCGT powerplant, and not intermediate/load shaping gas-fired units, as some parties suggest in their comments.

That leaves us with the selection of a specific level of lbs of CO_2/MWh emissions that is "no higher than the rate of emissions of greenhouse gases for combined-cycle natural gas baseload generation." The record in this proceeding establishes the following:[83]

- Based on the million British thermal units (MMBtus) consumed by CCGTs in California in 2004 and 2005 as reported in the CEC's Continuous Emissions Monitoring System (CEMS), CCGTs with

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[82] See, *Comments of the Green Power Institute on the Final Workshop Report,* October 18, 2006, Appendix A, pp. 18-19.

[83] Except as otherwise noted, the data summarized below is from the responses to the ALJ's request that are posted at www.cpuc.ca.gov/static/energy/electric/climate+change under Request #3.

capacity factors of 60% or more had emissions as low as 833 in 2004 and 794 in 2005.

- Based on the same CEMS reported data, CCGTs with capacity factors of 60% or greater had emissions as high as 1058 in 2004 and 1006 in 2005.
- The weighted average of emission rates based on the 2004/2005 CEMS data for baseload CCGTs is in the range of 856-915 lbs of CO_2/MWh, depending on whether energy or capacity is used as the weighting factor.
- Data from the CEC dating back to 2000 for CCGTs in the Western Energy Coordinating Council region show some facilities not included in the foregoing data with capacity factors greater than 60% and with emission rates ranging from 993-1208 lbs of $C0_2$/MWh.[84]

Based on the data provided on the record, we believe that establishing an EPS standard for CO_2 emissions of 1,000 lbs/MWh is reasonable. It represents a level that reflects emissions rates associated with both existing and new baseload CCGT units and, indeed, is somewhat above the 2004-2005 weighted average of the CEMS data (by capacity or energy). At the same time, it avoids establishing a standard that is representative of the most inefficient, older deemed-compliant CCGT powerplants currently in operation. In this way, our adopted level reflects the intent of the Legislature to base the EPS on CCGT emission rates, while acknowledging the concern reflected in the statute's grandfathering provisions that some of the older, less efficient CCGT powerplants currently operating may not be able to meet it.

We find that it is unnecessary to raise the EPS beyond the 1,000 lbs of CO_2/MWh level to recognize dry cooling technologies, as some parties suggest.

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[84] *Comments of PG&E on Draft Workshop Report*, September 8, 2006, p. 12.

The adopted EPS level reasonably takes into account that fact that dry cooling, which offers the benefit of lower water consumption, may reduce heat rate efficiencies resulting in higher GHG emissions. As DRA points out in its comments, the reduction in efficiency for dry cooling is very minor. In Resolution E-3940, approving the 2005 Market Price Referents for the RPS, we found that a 1.5% increase in the referent CCGT baseload powerplant heat rate was an appropriate value to use to reflect the impact of dry cooling, noting that such an adjustment was supported by the rule-of-thumb adjustment (1.5%) recommended by General Electric for F-series turbines with dry cooling.[85] As DRA notes, even with this assumption, the heat rate of the market price referent was found to be 6,375 Btu/kWh, corresponding to a CO_2 emission rate of 765 lbs of CO_2 per MWh.[86]

In sum, we find that an EPS level of 1,000 lbs of CO_2/MWh to be reasonable, and we shall adopt it.

4.4. Application of EPS to Contracts: Deliveries or Underlying Facility?

One of the threshold design issues in Phase 1 is how the EPS should be applied to contracts. While all parties agree that the characteristics of the facility supplying the energy should be considered when applying the EPS to new ownership investments, there was considerable debate during Phase 1 on whether the same should apply when considering contract commitments. The discussion focused on the treatment of "specified contracts" since, by definition,

[85] See Resolution E-3980, April 13, 2006, pp. 9-10.

[86] *Opening Comments and Legal Arguments of DRA on the Final Workshop Report on Phase 1 Issues*, October 18, 2006, p. 11.

these are contracts where the generating units or facilities providing the power are known. We address the treatment of "unspecified" contracts in a separate section of this decision. (See Section 4.12.)

Some parties (including TURN, NRDC, UCS and WRA) recommend that this determination be made based on the annualized operations of the underlying facility or facilities, regardless of the type of contract deliveries. Staff supports this approach. Other parties (EPUC, CAC, SDG&E and SoCalGas) recommend that the Commission assess the capacity factor based only on the energy made available under the contract to the LSE, rather than on the operations of the underlying powerplant. These parties contend that this approach is supported by the "supplied under" language of in §§ 8341(a),(b)(1) and (3), in which the Legislature directs that baseload generation "supplied under" a contract or long-term financial commitment shall comply with the EPS.

In our view, accomplishing the goals of SB 1368 and this Commission's GHG reduction policies requires us to look at the characteristics and emissions of the powerplant(s) being contracted for, *not* just the characteristics of the contracted-for deliveries, as some parties propose. Indeed, it is the characteristics of the powerplant(s) underlying those financial commitments that create the potential financial risk to California consumers and exposure to future reliability problems that this Commission and the Legislature seek to reduce through the establishment of an EPS, as both have clearly expressed. (See Section 3 above.)

Moreover, the rules of statutory construction support a facility-based application of the EPS. As the Courts have stated on numerous occasions: "It is a cardinal rule of statutory construction that in attempting to ascertain the legislative intention effect should be given, whenever possible, to the statute as a whole and to every word and clause thereof, leaving no part of the provision useless or deprived of meaning."[87] Focusing on the phrase "supplied under" to conclude that the Legislature intended for EPS compliance to apply only to contracted-for power deliveries violates this rule. In particular, it would render useless the language of § 8341(4) that states:

> "In determining whether a long-term financial commitment is for baseload generation, the commission ***shall consider the design of the powerplant and the intended use of the powerplant…***"[88]

We also note that in all instances where it appears in the statute, the phrase "supplied under" follows the term "baseload generation" which is defined by § 8340(a) in terms of *electricity generation from a powerplant* that is designed and intended to provide electricity at an annualized plant capacity factor of at least 60%. The term "plant capacity factor" is also defined by § 8340(l) in reference to the underlying plant operations, i.e., as *the electricity the unit could have produced it had it been operated at its rated capacity*. We interpret SB 1368 to ensure that LSEs do not enter into contracts with powerplants designed and intended for baseload operations with GHG emissions higher than combined cycle natural gas powerplants. Had the Legislature intended to only consider the terms of the contract (or deliveries under that contract) rather than the underlying facility in determining whether a contract supplied "baseload generation," it would

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[87] *Gay Law Students Association* v. *Pac. Tel. & Tel. Co.*, (1979) 24 Cal.3d 458, 478, citing *Weber* v. *County of Santa Barbara* (1940) 15 Cal.2d 82, 86.

[88] § 8341 (b) (4), emphasis added.

have defined that term as well as "plant capacity factor" to clearly reflect that intent.[89]

We conclude that determining whether the EPS applies to a resource should be made based on the characteristics of the generating facilities underlying the contract, and not on the contracted-for deliveries. As staff notes in its final report, for specified contracts the capacity factor, average heat rate and emissions factor of the underlying facility or facilities supplying power should be readily available, since operators are required to provide this information to multiple regulatory agencies such as the Environmental Protection Agency and California Air Districts. Pursuant to § 8341(4), we will use reported information, information from permits and certificates, as well as any other information we deem to be relevant in order to establish the design and intended use of the generating facilities underlying the contract.

As discussed in Section 4.7 below, there could be instances where different resources or technologies might be generating power at the same location. For example, a renewable resource (e.g., wind) might be located in the same generating station as a fossil-fueled unit. So that there is no ambiguity in our rules, we clarify that generating units utilizing different resources or technologies, no matter if they are at the same location, must each be evaluated

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[89] The legislative history of SB 1368 supports the plain meaning of the statute. During the Senate Third Reading of SB 1368, the committee report states that "the purpose of this bill is to prevent long-term investments *in power plants* with GHG emissions in excess of those produced by a combined-cycle natural gas power plant." The report also states that the bill would apply to contracts for "baseload power," where baseload power is defined as "electricity generation *from a power plant* that is designed to provide electricity at least 60% of the total hours in a year (a 60% capacity factor)." See, for example, Senate Third Reading of SB 1368, as amended August 21, 2006, p. E, F.

separately for the purpose of determining whether the resource operates as baseload generation and, if so, whether its emissions rate complies with the EPS.

4.5. LSE Contracts With Customer Generators

A related issue is how to treat LSE contracts with powerplants that also generate power for on-site load (referred to interchangeably in comments as "customer generators," "self-generators" or "self-generation facilities"). EPUC/CAC presents the example of a customer generator that has a capacity of 50 MW and uses 45 MW to serve the industrial loads of its own site, selling any surplus energy to the utility on an as-available basis. If the unit were assessed, it would appear to be operating at a very high capacity factor. However, if the deliveries to the grid under the utility contract were assessed, those deliveries would be at a very "low capacity factor."[90] EPUC/CAC takes the position that only the electrical generation output actually delivered to the grid should be considered in determining whether the EPS will apply. In their view, it would be unreasonable to consider a 5 MW as-available sale by a customer generation facility a "baseload" facility in the utility portfolio.

NRDC, TURN, UCS and WRA disagree. They argue that self-generation facilities should be evaluated against the EPS based on the operational characteristics of the underlying facility, consistent with the application of the EPS to all specified contracts. Even if the amount of energy delivered to the grid is small, they contend that the facility is still a resource upon which the LSE relies, and long-term reliability risks would still be a concern if the facility is

[90] The "capacity factor" in this instance would be calculated as the amount of contracted-for deliveries divided by the annual average output of the facility.

carbon-intensive. In their view, the Commission should avoid situations where the LSE makes separate arrangements for on-site high-polluting resources, since the same risks apply to those facilities.

We agree that the EPS should be applied consistently to the characteristics of the underlying facility or facilities supplying power under contract to the LSE, irrespective of whether those facilities are operated by a customer generator or by a merchant generator (i.e., that does not use any of the power produced on site). Under either circumstances, the operating characteristics of the powerplant(s) underlying contracts of five years or more with an electrical corporation, electric service provider or community choice aggregator, as defined under the statute, should be considered in assessing whether the EPS applies.

We find no merit to EPUC/CAC's argument that this approach creates "a possible discrimination" between customer-owned generation and merchant generation. In fact, the example EPUC/CAC presents to support this argument focuses on powerplants with no operational similarities at all except for the amount of power contracted for with the LSE.[91] The purpose of the EPS is not, as EPUC/CAC contend, to ensure that generators with similar deliveries to the grid are treated comparably. Rather, as discussed above, the purpose of the EPS is to ensure that LSEs do not enter into long-term financial commitments with powerplants designed and intended for baseload operations that emit GHG at a

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[91] See the EPUC/CAC example: A merchant generator that is a combustion turbine with 5 MW capacity that has a capacity factor of 20% and an industrial customer generator with 30 MW capacity that operates at a 90% capacity factor and has a contract with an LSE to supply no more than 5 MW. *Reply Comments of EPUC/CAC on the Final Workshop Report,* October 27, 2006, pp. 8-9.

rate higher than a CCGT powerplant. Under EPUC/CAC's example, it is therefore consistent with this purpose that the 30 MW generator operating at a 90% capacity factor is subject to the EPS, whereas the 5 MW generator operating at a 20% capacity factor is not (assuming that the output of both facilities is under contract with an LSE for a term of five years or greater).

Moreover, we find no merit to EPUC/CAC's contention that applying the EPS to the underlying facility in the case of customer generators represents an attempt by this Commission to exceed its jurisdiction, and is "not allowed by law."[92] In particular, EPUC/CAC argues that § 218 "excludes cogenerators from the jurisdiction of the Commission to the extent their generation is delivered on-site or over the fence," and therefore concludes that the Commission's jurisdiction is limited by law to the contract deliveries to the LSE.[93]

By law, the EPS governs the long term financial commitments of LSEs to *any* baseload generation, and SB 1368 directs this Commission to design and implement an EPS for this purpose.[94] Therefore, once a customer generator decides to offer power over and above its own (or over the fence) on-site consumption to an LSE under a contract with a term of five years or more, the power supplied under that contract comes under our purview for the purposes of evaluating the LSE's (not the customer generator's) compliance with the EPS. For the reasons discussed above, we have determined that the criteria for determining whether or not the long-term financial commitment of the LSE

[92] *Ibid.*, p. 10.

[93] *Id.*

[94] §§ 8341(a) and (b).

meets the EPS (annualized capacity factor and emissions rate) should, and statutorily must, apply to the underlying facility.

4.6. Treatment of Partial Contracts

The issue of how to treat partial contracts is also related to the question of whether the contract terms or the underlying facility should be considered when applying the EPS. The example discussed at the workshop was a summer product contract for power from a specified pulverized coal plant. Staff recommends that the expected capacity factor of the contractual commitment (not the underlying powerplant(s)) be considered for any partial-year contract. Therefore, if the commitment under the contract represented less than a 60% capacity factor on an average annual basis, it would not be subject to the EPS.[95] In staff's view this is reasonable because such contracts would likely be addressing seasonal reliability issues. PG&E concurs with this approach for similar reasons.[96]

NRDC, GPI, IEP and others object to this treatment of partial contracts, arguing that a blanket exemption for seasonal procurements is both unnecessary and inconsistent with the intent and purpose of the EPS. In particular, they argue that if the purpose of a partial year contract is to address system reliability concerns, then the contract would probably be less than five years in duration and therefore not subject to the EPS. In any case, they point out that such concerns can be addressed by providing for case-by-case review of reliability exemptions, rather than creating a loophole for partial contracts.

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[95] Under this treatment, the "capacity factor" would also be calculated by dividing the amount of contracted-for energy deliveries by the annual average output of the facility.

[96] *Comments of PG&E on Draft Workshop Report,* September 8, 2006, p. 9.

We agree. Considering the expected capacity factor of the partial year contractual commitment (rather than of the underlying powerplant) is clearly inconsistent with other aspects of the EPS we adopt today. Such treatment could easily permit baseload generation that would otherwise be prohibited from supplying power to the LSE to supply that power by simply limiting the time period for deliveries. The example presented by IEP clearly illustrates this inconsistency:

> "For example, an out-of-state coal plant might enter into a long-term contract to provide baseload power to a California [LSE] for the months of May through October. This unit could also sell its output to another buyer (either an out-of-state buyer or a different California LSE) for the months of November through April. Even if the unit underlying this contract were to run at or near a 100% capacity factor level (certainly not a "shaping" resource by any stretch of the imagination), staff's recommended annual average basis for evaluation would show this resource to have less than a 60% capacity factor and thus not be subject to the screen."[97]

We agree with NRDC, TURN, UCS, GPI, IEP and others that there is no compelling reason to make a distinction for partial procurements based on horizontal or vertical slices of a facility's output. We already incorporate design parameters into the EPS that will minimize the potential impact of the standard on reliability concerns, and as we discuss in Section 4.8.5, provide for a case-by-case exemption to the EPS based on reliability considerations. This enables us to carefully assess those circumstances where waiver of the adopted EPS may be

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[97] *Comments of the Independent Energy Producers Association on the Draft Staff Workshop Report*, September 8, 2006, pp. 2-3.

necessary to address reliability issues through a long-term seasonal contract, without creating an unnecessary loophole in our application of the EPS.

Instead, we will apply the same principle to partial contracts that we apply to other specified contracts, namely, that the generating facility underlying the contract (and not the contracted-for deliveries) will determine whether the commitment is for baseload generation and, if so, the associated emissions rate.

4.7. Treatment of Multiple Generating Sources, Including Contracts with Renewables Firmed by Non-Renewable Resources

Under the staff proposal, each individual generating source underlying a contract where those sources are specified must meet the EPS, with the exception of "firmed renewable products." Under these types of contracted-for deliveries, a renewable resource provides as-available energy and a non-renewable source or sources provide additional "firming" energy, so that the total amount of energy sums to an agreed upon amount. For firmed renewable products, staff proposes that the blend of the emissions from the renewable and non-renewable resources must meet the EPS. In the case of a renewable resource firmed by an unspecified resource, staff would similarly blend the imputed emissions value for that unspecified unit with those of the renewable resource. (See Section 4.12 below on how staff proposes to impute emissions rates for unspecified sources.)

In general practice, staff's proposal for firmed renewable products means the following: As long as the proposed procurement of firmed renewable energy is for deliveries with an annual average capacity factor below the 60% threshold level, then the procurement is automatically exempt from the interim EPS. If the procurement has an annual average capacity factor above this threshold, it generally means that half of the energy deliveries or more under the procurement will be from the non-renewable firming resource, and the procurement would be subject to the interim EPS. Under these circumstances the procurement would be judged as a whole (emissions of renewable and firming energy combined on an annual average basis), rather than applied to each generator separately.

There is general concurrence among parties with staff's overall recommendation on the treatment of contracts with multiple generating sources, namely that each source be treated individually for the purpose of determining both the capacity factor and net emissions.[98] However, there is considerable debate over staff's blending proposal with respect to firmed renewable products. We discuss the range of views below.

PG&E does not support staff's position on this issue. Instead, PG&E recommends that any resource eligible under the RPS program should be

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[98] EPUC/CAC requests that the Commission specifically clarify that the treatment of multi-unit contracts would be applied on a unit basis where two or more units in a generating station are used for different purposes, as illustrated in the following example:

> "A multi-unit facility may enter into one contract with an LSE. The contract could provide for 50 MW of energy at an 80% capacity factor from Unit 1, and a 20 MW peaking product, not to exceed a 30% capacity factor, from Unit II. The contract for the production from Unit 1 would pass the screens, and the EPS would be applied to Unit 1. However, the product from Unit II would not pass the screens for either minimum size or baseload capacity factor." (*Comments of EPUC/CAC on Final Workshop Report*, October 18, 2006, pp. 11-12.)

However, this example (and EPUC/CAC's request for clarification) is only relevant in the context of an EPS that looks at contract deliveries or products, rather than the operations of the underlying powerplant (as that term is defined in SB 1368). As discussed throughout today's decision, this is not the context for our adopted EPS (nor is consideration of a size threshold), and therefore the clarification that EPUC/CAC seeks here is neither relevant nor appropriate.

categorically deemed in compliance with the EPS, without regard to the characteristics of any firming non-renewable resource behind the RPS-eligible resource.[99] LL Power supports this approach.

GPI opposes PG&E's proposal for a blanket exemption to the EPS for firmed renewable products, arguing that this could provide a significant loophole for bringing high GHG-emitting baseload resources into California. Like staff, GPI examines the issue of how to treat a renewable product firmed by a non-renewable resource from the viewpoint of contract deliveries. GPI gives the example of a firmed wind contract for 8,760 hours of scheduled energy deliveries at the wind generator's rated capacity, where some two-thirds or more of the delivered energy under the contract would be firming power, rather than renewable. In this instance, GPI argues that a blanket exemption could permit contract deliveries of a baseload product that does not meet the EPS on even a blended basis. Instead, GPI supports the staff proposal to apply the EPS on a blended basis to firm renewable products, rather than apply the EPS separately to each source of power. GPI argues that this is appropriate because the relative contributions of the two sources of power under the procurement (renewable and firming) are intrinsically linked.

In contrast, NRDC, TURN, UCS, WRA and DRA argue that staff's proposed treatment of these contracts (and by extension, GPI's) runs counter to the intent of SB 1368 that the standard is to be applied to the underlying facilities behind a contract, not a blend of their emissions. These parties are particularly

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[99] Resources that count towards the utilities' RPS requirements are established by the CEC and set forth in The RPS Eligibility Guidebook at:

Footnote continued on next page

concerned that this exception would allow high-emitting resources that would never pass the standard alone (such as pulverized coal) to be blended with zero-emitting renewable resources. In their view the interim EPS should be applied in a manner consistent with the plain language of the statute, even for firmed renewable products.

Plumas-Sierra Rural Electric Cooperative (Plumas-Sierra) does not comment on the specific proposals described above, but generally urges that "that Commission implementation of the standard not result in a perverse situation where an entity delivering a totally clean and renewable resource is penalized by having a firming facility deemed a 'baseload resource.'"[100]

In our view, only the position advocated by NRDC, TURN, UCS, WRA and DRA is consistent with the plain language of SB 1368. As we discussed in Section 4.4 above, SB 1368 requires that EPS-compliance be based on the underlying facility or facilities producing power, not just the delivered product under a contract. Had the Legislature intended to carve an exception for firmed renewable products, they could have explicitly done so.[101] However, they did not, and we cannot reconcile the position put forth by staff and PG&E with the direction of the Legislature. As NRDC and others point out, allowing an exception for firmed renewable products would permit high-emitting baseload

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http://www.energy.ca.gov/2006publications/CEC-300-2006-007/CEC-300-2006-007-F.PDF.

[100] *Comments of the Plumas-Sierra Rural Electric Cooperative…on the October 2, 2006 Workshop Report and Staff Proposal for an Interim Emissions Standard*, October 18, 2006, p. 4.

[101] Nor does the legislative history of SB 1368 provide any indication that the Legislature intended to provide such an exemption for firmed renewable products.

resources that would never pass the standard alone to be blended with zero-emitting renewable resources, thereby circumventing the intent of the interim EPS. Accordingly, for contracts with multiple generating sources, each source must be treated individually for the purpose of determining both the annualized capacity factor and net emissions.

We note that SB 1368 does not specifically address instances where different resources or technologies might be generating power at the same location, e.g., a renewable resource located in the same generating station as a fossil-fueled unit. We do not believe that the Legislature intended for the term "powerplant" to treat each of these distinct and separate generating sources as a single facility for the purpose of applying the EPS. To do so would effectively permit the blending of high-emitting resources with low- or zero-emitting resources simply due to the physical co-location of the generating facilities. This could lead to an absurd result where power stations are expanded in order to co-locate high emitting generator sources with renewable or low-emitting CCGTs, in order to circumvent the EPS rule. To avoid this absurd result, we clarify that generating units utilizing different resources or technologies, no matter if they are at the same location or contracted for under the same purchase power agreement, must each be evaluated separately for the purpose of evaluating whether the resource operates as baseload generation and, if so, whether its emissions rate complies with the EPS.

4.8. Proposed Exemptions from the EPS Standard

Staff recommends four areas of exemptions from the EPS standard. The first is a categorical exemption for any covered procurement that represents a commitment of less than 25 MW. This size threshold would be based on the unit size for new ownership investments, and on the amount of power contracted for under either specified or unspecified contracts.

Staff also recommends three areas where the Commission could provide exemptions from the EPS on a case-by-case basis, at its discretion. The first is a research, development and demonstration (RD&D) exemption for higher-emitting facilities upon demonstration that the commitment in question would make a significant contribution to developing a lower-emitting resource mix in the future. In addition, staff recommends that the Commission allow for reliability and cost-based exemptions on a case-by-case basis, at the discretion of the Commission.

We discuss each of these proposed exemptions, as well as additional ones recommended by parties in their comments, in light of SB 1368.

4.8.1. Small Size Exemption

As discussed in the draft and final reports, staff concludes that a 25 MW size threshold is reasonable because, among other things, it is compatible with the Air Districts and federal environmental regulations and would comport with the Northeastern Regional Greenhouse Gas Initiative emissions cap program. Prior to the passage of SB 1368, most parties supported the staff proposal to exclude specified resources under 25 MW from the EPS for these and other reasons. In addition, many parties supported staff's recommendation to apply the size same threshold to all contracts, including unspecified, in order to maintain consistency and to minimize administrative complexity.

Since the passage of SB 1368, however, IEP, DRA, GPI and SCE conclude that a size exemption is not permissible under the new law, and now recommend against any size exemption for that and other reasons. While NRDC, TURN, UCS and WRA acknowledge that the language of the statute supports the argument for not having a size threshold at all, these parties still support a *de minimus* size threshold of 5 MW, consistent with the maximum size limit under the Self-Generation Incentive Program. They also recommend that the size threshold apply to the underlying facility, not the contract or amount delivered to the grid. These parties oppose any size exemption for unspecified contracts, since it is impossible to identify the resources behind these contracts

PG&E, on the other hand, argues that the staff proposal for a 25 MW size threshold for both specified and unspecified contracts is consistent under SB 1368, and continues to support this proposal.[102]

In our view, a size exemption of any size is incompatible with the provisions of SB 1368. Section § 8341(a) directs that "no load-serving entity or local publicly owned electric utility may enter into a long-term financial commitment unless *any* baseload generation supplied under the long-term financial commitment complies with the green house gases emission performance standard established by the commission" and § 8341(d)(1) requires this Commission to "establish a greenhouse gases emission performance standard *for all* baseload generation of load-serving entities" by February 1, 2007. (Emphasis added.) Nowhere in the statute does the language suggest that "all" or "any" may be qualified by the size of generating units covered or contracted-for deliveries. In its discussion of this issue, PG&E fails to mention or consider

[102] PG&E basically argues that since SB 1368 authorizes the Commission to adopt rules to implement and enforce the EPS required by SB 1368, the Commission may balance the GHG reduction goals of the Legislature with other goals and conclude that there is little risk that a small size exemption will undermine the intent of SB 1368. See *Comments of PG&E on Final Staff Recommendation on Greenhouse Gas Emissions Performance Standard*, October 18, 2006, pp. 2-3

the plain meaning of § 8341(a) or 8341(d)(1), thereby violating a basic canon of statutory construction.[103] As the courts have noted on many occasions: "It is a cardinal rule of statutory construction that in attempting to ascertain the legislative intention effect should be given, whenever possible, to the statute as a whole and to every word and clause thereof, leaving no part of the provision useless or deprived of meaning."[104]

We therefore cannot reconcile PG&E's position on this issue with the plain language of SB 1368. The legislative history of SB 1368 also provides no indication that the Legislature considered including an exemption for facilities or commitments under a certain size. Moreover, even though a small size exemption has some appeal in terms of administrative simplicity (i.e., reducing the number of procurements subject to the EPS), the selection of the size threshold would be an arbitrary one, and could have the unintended consequences of driving down the size of high-emitting facilities for the sole purpose of obtaining an exemption from the EPS. Moreover, a blanket exemption that eliminates what could amount to be many facilities from EPS compliance could expose ratepayers to significant future risks and costs.

We also interpret SB 1368 to require that all LSEs, irrespective of service territory size, must comply with the provisions of SB 1368. In its comments on the final report, CEED suggests that SB 1368 provides for an exemption for small utilities under § 8341(d)(9), and recommends that we permit one.[105] As discussed

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[103] *Id.*

[104] *Gay Law Students Association* v. *Pac. Tel. & Tel. Co.,* (1979) 24 Cal.3d 458, 478, citing *Weber* v. *County of Santa Barbara* (1940) 15 Cal.2d 82, 86.

[105] *CEED's Opening Comments on Final Workshop Report*, October 18, 2006, p. 6.

in Section 5.3 below, § 8341(d)(9) states that the Commission may accept proposals for alternate compliance from small (less than 75,000 retail end-use customers in California) multi-jurisdictional utilities. However, the statute does not provide for a blanket exemption from the EPS based on service territory size. Moreover, a blanket exemption for all utilities with less than 75,000 customers would not achieve the same level of emission reductions and associated reduction in future risks and costs intended by the Legislature.

For the reasons stated above, we do not adopt an exemption to EPS compliance based on the size of the facility or contractual commitment. Nor do we adopt an exemption for small utilities, except as specifically provided for under § 8341(d)(9) for multi-jurisdictional electrical corporations that meet the alternative compliance requirements of that section. (See Section 5.3 below.)

4.8.2. RD&D Exemption

Staff's recommendation for a case-by-case RD&D exemption is supported by a number of parties, including Carson Hydrogen Power Project, San Francisco Community Power, PG&E, PacifiCorp, SDG&E and SoCalGas. These parties generally argue that an RD&D exemption will assist in the introduction and adoption of new technologies that can greatly reduce GHG emissions, thereby furthering the Commission's and State's energy policies. In PacificCorp's view, the EPS will act as a deterrent to the early commercialization of IGCC technology and CO_2 sequestration projects unless we include an RD&D exemption.[106] SCE argues that, without an RD&D exemption, the EPS will drive investment

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[106] *Post-Workshop Comments of PacifiCorp, July 27, 2006, p. 4.*

towards increased reliance on natural gas, while failing to encourage investments in new technologies.[107]

Other parties, including GPI, NRDC, TURN, UCS, WRA, DRA and Calpine, oppose the staff recommendation. They argue that, although the Commission should support RD&D and deployment of advanced technologies, it must not do so at the expense of potentially undermining the EPS. In particular, they contend that because the EPS is a gateway standard, the mere assurance that an Integrated Gasification Combined Cycle (IGCC) coal plant "has or will have in a reasonable period of time the capacity and existing plan to capture and store carbon dioxide" is not sufficient to ensure that it will actually realize such a plan and reduce and maintain emission at or below the EPS limit in the future.[108]

We believe SB 1368 provides the flexibility to both encourage new technologies while meeting the EPS. In particular, the Legislature directed us to calculate emissions rates based on "net emissions" from the production of electricity and, with respect to CO_2 sequestration projects, and provides for the following:

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[107] *Post-Workshop Comments of SCE, July 27, 2006.*

[108] In discussing the RD&D exemption, Staff suggests that the following type of coal generation plant could qualify: "…[A]n advanced coal facility that has an equal or better emission rate than the estimated [Integrated Gasification Combined Cycle] average heat rate and emissions, and that has or will have within a reasonable period of time the capacity and existing plan to capture and store carbon dioxide…." *Final Report*, p. 27.

> "Carbon dioxide that is injected in geological formations, so as to prevent releases into the atmosphere, in compliance with applicable laws and regulations shall not be counted as emissions of the powerplant in determining compliance with the greenhouse gases emissions performance standard."[109]

Therefore, any covered procurements with a baseload facility utilizing such CO_2 sequestration projects will still need to meet the EPS (in contrast to a blanket RD&D exemption), but in calculating the net emissions rate we will not count the CO_2 that is sequestered through injection in geological formations, as directed by SB 1368. Because of the unique nature of such CO_2 sequestration projects, we will require LSEs to file an application requesting a Commission finding of EPS-compliance for any covered procurement that employs geological formation injection. As part of this filing, the LSE shall provide documentation demonstrating that the geological formation injection project has a reasonable and technically feasible plan that will result in a permanent sequestration of CO_2 once the injection project is operational. This may mean that the sequestration project will become operational after the powerplant comes on line or the LSE enters into the contract. In implementing §§ 8341(d)(2) and (5), we clarify today that we will determine EPS compliance for such powerplants based on reasonably projected net emissions over the life of the facility. The LSE is required to make a showing of EPS compliance by presenting projections (and documenting those projections) of net emissions over the life of the powerplant. This type of showing will ensure that the purposes of SB 1368 are served.

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[109] § 8341 (d)(5).

In sum, we conclude that a RD&D exemption for non-compliant baseload resources is inconsistent with SB 1368, but clarify how §§ 8341(d)(2) and (5) will be implemented under our interim EPS rules. We also remind parties that all RD&D projects that have an annualized plant capacity factor of less than 60% will not be subject to the EPS standard.

4.8.3. Exemption for Qualifying Facilities (QFs)

Several parties[110] argue that QFs should be exempt from the EPS because the EPS conflicts with and is thereby preempted by federal law, specifically the Public Utility Regulatory Policies Act of 1978 (PURPA).[111] In particular, parties argue that the EPS would conflict with the electric utilities' mandatory purchase obligation in 16 U.S.C § 824a-3.[112] According to these parties, applying an EPS to new contracts (or contracts up for renewal) of five or more years violates federal law to the extent it may disallow QFs from selling energy on a long-term basis to electric utilities.

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[110] Including IEP, EPUC, CAC and CCC.

[111] A QF is a generating facility that meets the requirements for QF status under PURPA and part 292 of the Commission's Regulations (18 C.F.R Part 292). There are two types of QFs: (1) Cogeneration facilities that meet the requirements of 18 C.F.R §§ 292.203(b) and 292.205 for operation, efficiency and use of energy output, and (2) Small power production facilities whose primary energy source is renewable (e.g., hydro, wind solar, biomass, waste or geothermal resources) and that otherwise meets the requirements of 18 C.F.R §§ 292.203(a), 292.203(c) and 292.204. Small power production facilities are limited in size to 80 MW, with the exception of certain types of facilities certified prior to 1995.

[112] According to a recent FERC rulemaking (Docket No. RM06-10-000; Order No. 688), California electric utilities are still subject to PURPA's mandatory purchase obligation. Nonetheless, as discussed herein, SB 1368 is consistent with the provisions of PURPA, including the electric utilities' mandatory purchase obligation.

In 1978, Congress enacted PURPA (16 U.S.C. § 824a et seq.) which amended the Federal Power Act. Congress believed encouraging the development of certain cogeneration and small power production facilities, which meet specific criteria under 16 U.S.C. § 796 (collectively called QFs), would reduce demand for traditional fossil fuels and increase the use of alternative energy sources.[113]

16 U.S.C. § 824a-3 states that the Federal Energy Regulatory Commission (FERC) shall prescribe rules that "require electric utilities to offer to …purchase electric energy from such facilities." In accordance with 16 U.S.C. § 824a-3, FERC promulgated 18 C.F.R. § 292.303. 18 C.F.R. § 202.303 states that "Each electric utility shall purchase, in accordance with § 292.304 [Rates for purchases], any energy and capacity which is made available from a qualifying facility: (1) Directly to the electric utility; or (2) Indirectly to the electric utility. . ." Although both the statute and the regulation require electric utilities to purchase energy from QFs, neither requires the utilities to enter into long-term contracts.

Under PURPA, state regulatory bodies are required to implement FERC's rules regarding purchases and sales between QFs and electric utilities. (16 U.S.C. § 824-a3(f)).[114] States may thereby determine some of the circumstances under which sales of electricity by QFs to electric utilities take place.[115] In its

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[113] *FERC v. Mississippi,* 456 U.S. 742, 750-51 (1982).

[114] *Accord Indep. Energy Producers Ass'n, Inc.* v. *Cal. Pub. Util. Comm'n*, 36 F.3d 848, 856 (9th Cir. 1994) (PURPA delegates to the states broad authority to implement PURPA).

[115] In addition, states may regulate environmental issues related to QFs. "While [PURPA] permits certain facilities to be exempt from State and Federal laws, it excludes exemptions from environmental laws. Thus a qualifying facility may not be built or operated unless it complies with all applicable local, State, and Federal zoning, air, water, and other environmental quality laws, and unless it obtains all required

Footnote continued on next page

implementation of PURPA, this Commission has previously determined that PURPA does not require utilities to enter into long-term contracts to purchase QF power. As this Commission stated in D.05-09-022:

> "Neither 18 C.F.R. section 292.303 or 18 C.F.R. section 292.304(b) [FERC Rules implementing PURPA] specifies an obligation of this Commission, or any other entity, to adopt a vehicle to deliver available QF power to the utilities. Rather, . . . these CFR sections require a utility to take power made available by a QF, and to pay the cost for power that is equivalent to the utilities avoided cost of procuring or producing that power. . . . Absent from the sections . . . is any mandate that this Commission must either require long-term contracts or establish any specific delivery vehicle."

Similarly, in D.96-10-036 we stated: "We begin with Section 210 (16 U.S.C. Section 824a-3(h)), which obligates utilities to purchase electricity from QFs. . . . Taking a look at the statute, we find no mandated minimum term for PURPA required purchases. Looking to FERC regulations, we similarly find no mandated minimum term." (p. 21, *mimeo.*) In short, although federal law mandates the purchase of energy from QFs, it does not require utilities to enter into long-term contracts. Therefore, an EPS that does not prohibit a utility from purchasing energy from a QF does not conflict with federal law.

Contrary to opponents' arguments, as the language of both PURPA and the FERC regulations demonstrate, there is no provision that requires that QFs be allowed to enter into long-term contracts. After implementation of SB 1368, electric utilities will still be required to purchase energy from QFs in conformity

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permits." *Small Power Production and Cogeneration Facilities – Environmental Findings*, 10 FERC ¶61,134 at 61,632 (1980). As an environmental law, SB 1368 is consistent with states' regulatory authority over QFs, as determined by FERC.

with federal law. Utilities will simply be limited from entering into new, or renewal, long-term contracts with baseload QFs that do not meet the EPS.[116] QFs that do not comply with the EPS will still be able to enter into contracts of less than five years with the utilities. Thus we conclude that it is fully possible for electric utilities to abide by both federal law (PURPA) and SB 1368 as implemented by this Commission. Since the EPS will only apply to new contracts (or contracts up for renewal) of five or more years, electric utilities should be fully capable of complying with both federal and state law and regulation.

Furthermore, SB 1368 does not permit the Commission to exempt QFs from complying with the EPS unless there is a conflict with PURPA regulations. SB 1368 requires that:

> (a) No load-serving entity or local publicly-owned electric utility may enter into a long-term financial commitment unless any baseload generation supplied under the long-term financial commitment complies with the greenhouse gases emission performance standard established by the commission, pursuant to subdivision (d), for a load-serving entity, or by the Energy Commission, pursuant to subdivision (e), for a local publicly owned electric utility.
>
> (b)(1) The commission shall not approve a long-term financial commitment by an electric corporation unless any baseload generation supplied under the long-term financial commitment complies with the greenhouse gases emission performance standard established by the commission pursuant to subdivision(d).

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[116] The statute does not require any showing of compliance with the EPS for existing contracts.

SB 1368 requires that "the commission shall consider and act in a manner consistent with any rules adopted pursuant to [PURPA]" when we develop and implement the EPS. (§ 8341(d)(8).) As shown above, there is no conflict between SB 1368 and PURPA. Thus, requiring QFs to comply with the EPS is consistent with the PURPA regulation and we therefore conclude that we cannot grant QFs an exemption from the EPS required by SB 1368.

4.8.4. Exemption for Gas-Fired Cogeneration

EPUC/CAC urge the Commission to deem all existing gas-fired cogeneration in compliance with the EPS, and thereby categorically exempt from it. In their view, this would appropriately recognize that gas-fired cogeneration has emissions rates similar to or less than CCGTs and would avoid discrimination among forms of cogeneration.

In addition, EPUC/CAC assert that the EPS cannot reasonably be applied to bottoming-cycle cogeneration.[117] They request clarification that this technology is not included within the definition of "powerplants" under SB 1368. They argue that there are no emissions associated with the generation of electricity using a bottom-cycle generator—emissions are instead associated with the underlying industrial process. EPUC/CAC propose that the entire emissions output of such facilities should be exempt from EPS, regardless of whether the electrical output is used for on-site needs or is sold under contract to an LSE.

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[117] Bottoming cycle cogeneration (also referred to as industrial waste-heat powered generators) is employed in industrial processes such as oil and gas producing and refining operations. Electricity is generated using a heat recovery steam generator, which generates electricity from waste heat produced by an industrial process (such as the industrial process of calcining petroleum coke).

We do not adopt these recommendations. SB 1368 meant the EPS to apply to all cogeneration facilities since it specifies a rule for calculating the emissions of cogeneration facilities. (See § 8341(d)(3).) Had the Legislature intended to exempt gas-fired cogeneration from the EPS it would have explicitly done so. This is clearly not the case.

We also find no basis in SB 1368 for EPUC/CAC's assertion that bottoming-cycle cogeneration is not a powerplant. SB 1368 establishes that "powerplant" means "a facility for the generation of electricity" and bottom-cycling generation uses waste heat to generate electricity. In addition, SB 1368 does not distinguish between emissions from topping-cycle and emissions from bottoming-cycle cogeneration facilities.

Moreover, EPUC/CAC provide no evidence for their assertion that there are no emissions associated with the production of electricity using this technology. In fact, they acknowledge that when supplemental firing is used to enhance the performance of bottoming-cycle facilities, "any resulting emissions attributable to the supplemental firing may be considered in developing an emissions rate for the cogeneration facility."[118] Therefore, as PG&E and others suggest, the determination of net emissions from a bottoming-cycle plant should be made on a facility-specific basis.

In sum, consistent with the direction contained in SB 1368, today's adopted interim EPS will apply to cogeneration facilities. In Section 4.9 below, we address how to calculate the GHG emissions from cogeneration facilities, taking into consideration the thermal energy output contemplated by § 8341(d)(3). As

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[118] *Comments of ECAC/CAC on the Final Workshop Report*, October 18, 2006, p. 8.

discussed in that section, the calculations can be readily applied to bottom-cycle cogeneration facilities.

4.8.5. Reliability and Cost-Based Exemptions

Turning first to reliability exemptions, we note that there is general support for staff's recommendation that the Commission should be able to, at its discretion, provide for case-by-case exemptions to the EPS based on reliability concerns. We believe that this approach is reasonable because it provides us with flexibility to address specific system reliability concerns as they may arise during implementation. It is also workable to implement, since the need to provide an exemption for reliability reasons can be readily assessed as the "go, no-go" decision is being made for each new long-term financial commitments with baseload generation.

At the same time, we note that today's adopted EPS is purposely designed to both protect California ratepayers from long-term reliability risks while minimizing potential adverse impacts on short-term system reliability and associated costs. This has been accomplished by limiting the application of the EPS to long-term commitments, rather than short term transactions, and to baseload powerplants, rather than to those designed to be used for load shaping or peaking. In addition, as discussed further below, the interim EPS will be applied on a "gateway" basis, thereby providing LSEs with the flexibility to operate their facilities differently than originally designed or intended in order to address unanticipated short-term system reliability needs.[119] Therefore, we will adopt staff's recommendation for a case-by-case review of reliability exemptions

[119] Thus, for example, an LSE might be able to temporarily operate a plant at 60% or more capacity, even though the plant was not designed or intended for such operation.

only with the caveat that any consideration of such reliability exemptions comes with a heavy burden of proof on the LSE.

Any reliability exemptions must be pre-approved by the Commission and LSE requests for pre-approval shall be made by application. Pursuant to § 8341(d)(6), we will consult with the California ISO to consider the effects of such requests on system reliability and overall costs to electricity customers. Based on our analysis above, and after consulting on this matter with the California ISO, it seems unlikely that such exemption will actually be needed. However we still want to allow for the possibility of granting such an exemption in the event that unexpected reliability problems arise during implementation.

Several parties, including SCE, SDG&E and SoCalGas, support cost-based exemptions or economic safety valves on a case-by-case basis, particularly when significant economic impacts result from implementation of the EPS. These parties argue that consideration of cost impacts on a case-by-case basis is necessary to ensure that compliance costs do not escalate beyond customers' ability to pay for them. CEED argues that the "only true method to protect the ratepayer" is to establish a specific price cap for CO_2 emissions in implementing the EPS.[120]

Other parties, including GPI, NRDC and IEP strongly object to including case-by-case exemptions based on cost, or adopting other forms of economic safety valves or price caps in the EPS rule. They generally argue that the Commission's consideration of such cost-based exemptions opens the door to a parade of requests that would undermine the EPS.

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[120] *CEED's Opening Comments on Final Workshop Report*, p. 6.

In our view, approaches that would require us to assess costs or economic impacts on a case-by-case procurement basis are neither reasonable nor workable in the context of complying with the provisions of SB 1368. By its very nature and purpose, the EPS requires that each determination be made without respect to whatever other set of energy procurement opportunities a given LSE has available. This is because the EPS required by SB 1368 is designed to ensure that each baseload facility underlying a new long-term financial commitment meets a minimum level of performance, similar to an appliance efficiency standard. As GPI and others point out, in this context no single procurement can be said to cause significant cost or economic impacts, in and of itself, for a utility's customers.[121] Moreover, while CEED criticizes the staff proposal for failing to include cost containment measures, it does not provide any evidence that the costs to ratepayers of procuring compliant resources will be high, or consider the economic, health and environmental benefits associated with EPS compliance that have been expressed by this Commission and the Legislature.[122]

CEED also faults the staff proposal for not containing price caps. However, we note that CEED does not explain how a dollar-per-ton of CO_2 price cap would apply in the context of SB 1368 performance standard requirements, i.e., to each individual "go, no-go" long-term commitment decision made by the LSE. Perhaps CEED is suggesting that a long-term commitment to an otherwise non-compliant plant should nevertheless get a "go" rather than a "no go" because the cost of reducing GHG emissions for that particular plant would

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[121] In contrast, as discussed above, a specific reliability concern and associated costs may be assessed on a procurement-by-procurement basis during EPS implementation.

[122] GHG Policy Statement; SB 1368 (Section 1).

exceed more than $x/ton. Or, as in the case of the Massachusetts, Oregon and Washington price cap policies CEED mentions, the long-term commitment should be allowed because the LSE can pay $x/ton to a qualifying organization (e.g., the Massachusetts GHG Expendable Trust) for each ton above the standard. Such an approach would allow LSEs to build, or enter into long-term contracts with high GHG emitting plants without any reduction in those plants' emissions (so long as the cost of reducing GHG emissions at those plants is high). This would clearly undermine the SB 1368 goal of protecting ratepayers from the risks of entering into long-term commitments to high GHG emitting baseload facilities in the first place. In addition, we note that CEED fails to address how such a price cap could realistically be established by the statutory deadline of February 1, 2007.

However, we do find merit in Sempra's suggestion that some provision be made in our rules for "extraordinary circumstances, catastrophic events, or threat of significant financial harm" that may be arise during EPS implementation due to unforeseen circumstances.[123] Therefore, we will permit an LSE to file a petition for modification of the requirements of this decision under such extreme (and therefore highly unlikely) circumstances, so long as they are unforeseen circumstances not contemplated by SB 1368 and this decision. As in the case of reliability exemptions, our consideration of such a request comes with a heavy burden of proof on the LSE. Any such request must be pre-approved by the Commission and LSE requests for pre-approval shall be made by petition for modification of this decision.

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[123] *Comments of Sempra Global on Draft Workshop Report*, September 8, 2006, pp.7-8.

4.9. Calculation of GHG Emissions Associated with Cogeneration

SB 1368 requires the Commission to adopt a methodology for calculating the emissions rate associated with cogeneration facilities that recognizes both the thermal and electrical output associated with cogeneration.[124] The relevant provisions of SB 1368 are:

> 8341(d)(3) The commission shall establish an output-based methodology to ensure that the calculation of emissions of greenhouse gases for cogeneration recognizes the <u>total usable energy output</u> of the process, and includes all greenhouse gases emitted by the facility in the production of both electrical and thermal energy. (Emphasis added.)
>
> 8340(k) "Output-based methodology" means a greenhouse gases emission performance standard that is expressed in pounds of greenhouse gases emitted per megawatthour and factoring in the <u>useful thermal energy employed for purposes other than the generation of electricity</u>. (Emphasis added.)

Below, we briefly describe the output-based methodologies addressed in comments.

4.9.1. Alternative Methodologies

Three output-based methodologies were considered by the parties: (1) the Conversion Method (proposed by CAC/EPUC), (2) the Heat Rate of the

[124] Topping cycle cogeneration plants are the most common: They produce electricity first, and then the exhaust (thermal energy) from the electricity production is used in a process application (e.g., heating). Bottoming cycle plants produce heat for an industrial process first, and then electricity is produced using a waste heat recovery boiler. Bottoming cycle plants are only used when the industrial process requires very high temperatures, such as furnaces for glass and metal manufacturing and calcining coke. (See Section 4.8.4 above.) These terms have also been defined by FERC regulations implementing QF policy under PURPA (18 CFR §§ 292.202(d) and (e)).

Generator Method (presented as an option in the Assigned Commissioner's Ruling), [125] and (3) the Avoided Emissions Method (proposed by SDG&E/SoCalGas). Attachment 5 presents calculations using each method to illustrate GHG emissions rates both with and without a cogeneration credit for the thermal energy output.

4.9.1.1. Conversion Method

This method accounts for the thermal energy output associated with cogeneration as follows:

TOTAL GHG EMISSIONS FROM COGENERATION FACILITY
KWH ELECTRICITY + BTU THERMAL ENERGY (expressed in kWh)

Under the Conversion Method, the thermal energy measured in British thermal units (Btu) is converted into a kWh equivalent using the standard engineering conversion factor of 3.413 MMBtu per MWh, or 3413 Btu per kWh. This method is illustrated in Table A of Attachment 5 for a typical topping-cycle cogeneration facility, where 100 MMBtu of natural gas is burned (fuel in) to produce electricity. This process also produces waste heat (steam) as a by-product. The assumptions used to calculate the amount of electricity (7.8 MWh) and steam (48 MMBtu) output are described in Table D. [126] This example shows that, without accounting for any of the steam (thermal) output, the GHG emission rate for the cogeneration facility would be 1,492 lbs/MWh. This would

[125] *Assigned Commissioner's Ruling: Phase 1 Amended Scoping Memo and Request for Comments on Final Staff Recommendations*, October 5, 2006, Attachment 2.

[126] Information from bottoming-cycle cogeneration facilities can be readily entered into Tables A, B and C of Attachment 5 by showing the thermal output first, followed by electric output. Table D could also be rearranged to apply to bottoming-cycle cogeneration so that thermal output precedes electric output.

exceed the adopted EPS of 1,000 lbs/MWh. When the total output of the facility accounts for the steam output (producing the "cogeneration credit"), the effective GHG emission rate drops from 1,492 lbs/MWh to 537 lbs/MWh. Thus, without the cogeneration credit the facility does not pass the EPS, whereas with the credit the facility becomes EPS-compliant.

4.9.1.2. Heat Rate of the Generator Method

The formula for this method is the same as the Conversion Method described above. However, the conversion factor used to convert the BTU THERMAL ENERGY component of the formula into kWh is the heat rate of the generator (in Btu/kWh), rather than the engineering conversion factor of 3.413 MMbtu/MWh. As a result, the denominator of the equation above is divided by a much larger number (12.750 in the Table A example). This results in a smaller cogeneration credit and a higher resulting emissions rate. A comparison of the numerical examples in Attachment 5 shows that the Heat Rate of the Generator Method results in the highest emission rates among the three alternative approaches, all other things being equal.

4.9.1.3. Avoided Emissions Method

The Avoided Emissions Method is different from the two methods described above in that it separately determines the emissions rate for the thermal portion of the power output. This is done by calculating the emissions associated with a proxy steam boiler (with an assumed 80% efficiency). The emissions associated with the thermal portion are then deducted from the total emissions from the cogeneration facility, and the result is then divided by the electric output of the facility. The formula for the Avoided Emissions Method is as follows:

$$\frac{\textbf{(Total GHG Emissions From Cogeneration Facility)} - \textbf{(Total GHG Emissions From a Proxy Steam Boiler)}}{\textbf{Electric Power in MWh Generated by the Cogeneration Facility}}$$

Sample calculations using this method are presented in Attachment 5.

4.9.2. Discussion

Based on the record in this proceeding, we conclude that the Conversion Method is the preferred approach to use for the interim EPS for the reasons discussed below.[127]

We find the Heat Rate of the Generator Method to be incorrect as a simple matter of engineering. Specifically, it does not recognize that the thermal output (from the primary electric generation process) at a cogeneration facility will most likely be used directly as steam to do work, not converted into electricity in a secondary electric generation process that would incur the thermodynamic losses at the heat rate of the generator. In effect, using an electric heat rate to convert thermal energy output to kWh in this manner can double count the efficiency losses in the context of an output-based methodology.[128]

With respect to the Avoided Emissions Method, we concur with CCC, NRDC, TURN, DRA and others that this method is problematic for several reasons. First, as CCC points out, it may be very difficult to determine the

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[127] We note that no party supports the Heat Rate of the Generator Method, only SDG&E/SoCalGas support the Avoided Emissions Method, and all other parties commenting on this issue support the Conversion Method, i.e, CCC, CAC/EPUC, DRA, IEP, and NRDC/TURN/UCS/WRA (filing jointly).

[128] See *Opening Comments/Legal Brief on Final Workshop Report of NRDC/TURN/UCS and WRA*, October 18, 2006, p. 18.

characteristics of the stand-alone boiler whose GHG emissions are avoided by a cogenerator:

> "Is it the on-site boiler that the cogeneration unit replaced when it was first constructed? If the cogenerator or its thermal host continues to maintain an auxiliary boiler to provide steam when the cogeneration unit is down, is that the avoided boiler? Or is the avoided boiler a new, state-of-the-art boiler that the thermal host might use to replace the existing cogeneration unit?"[129]

Unraveling the answers to these questions during future power contract negotiations could end up being extremely complex and contentious. Moreover, the record in this proceeding does not provide us with a reasonable approach for estimating the emissions from the boiler that would be utilized in the absence of cogeneration. As NRDC and others point out, SDG&E/SoCalGas' assumption of 80% efficiency for such a boiler is an arbitrary selection. The CEC data that SDG&E/SoCalGas suggest could instead be used to determine the general efficiency of gas boilers may not be representative of boilers located outside of California. In any event, it would be inaccurate to assume a general efficiency for all boilers since not all cogeneration facilities are gas-fired. Finally, with respect to SDG&E/SoCalGas' alternate suggestion that the boiler efficiency be set at the minimum state or local standards, we note that the cogeneration facilities under consideration are not necessarily new facilities. Therefore, we concur with NRDC, TURN, UCS and WRA that it would not be accurate to assume that the boiler that would have been used in its place would have efficiencies that meet current standards.

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[129] *Reply Comments/Brief of the CCC*, October 27, 2006, p. 4, footnote 4.

A comparison of the Avoided Emissions Method with the Conversion Method also reveals that the Avoided Emissions Method may effectively ignore important fuel savings benefits associated with cogeneration. Across the range of usable steam output in our examples (e.g., near zero to about 55 MMBtu), we observe that the amount of fuel consumed in an avoided emissions analysis is always greater at the same level of usable steam output, everything else being equal. This appears to be due, in large part, to the fact that the Avoided Emissions Method uses two different resources to produce two different products (electricity and steam), whereas cogeneration uses one process that captures the benefit of two products. As a result, the Avoided Emissions Method may calculate an emissions rate based on the use of more fuel than a cogeneration facility might otherwise use during its actual operation.

In contrast to the Heat Rate of the Generator Method, the Conversion Method represents an output-based method that appropriately recognizes that the thermal output of a cogeneration facility can be used directly as steam to do work, and not for the secondary production of electricity. Relative to the Avoided Emissions Method, the Conversion Method has the advantage of being more accurate in calculating the actual emissions rate of the cogeneration facility, since it takes into account the actual thermal output of the cogeneration facility. It also is easier to implement and administer because it does not involve making assumptions about the type of boiler "avoided" and associated emissions rates. Finally, as discussed above, the Conversion Method fully recognizes the fuel savings benefits associated with cogeneration. For these reasons, we adopt the Conversion Method of calculating cogeneration emission rates for the purpose of determining compliance with the interim EPS.

In their comments, some parties who support the Conversion Method express concern over how it may be implemented. In particular, SCE contends that, as currently formulated by EPUC/CAC, the method does not take into account the losses from converting available thermal energy into "useful work." NRDC, TURN, UCS and WRA express concern that the EPUC/CAC proposed formula does not acknowledge that some of the "available" thermal output may be wasted (not "used") by the thermal host. These parties suggest that further clarifications or adjustments to the formula are needed to ensure that "the useful thermal energy employed for purposes other than the generation of electricity is factored into the calculation," as directed by § 8340(k).

We believe that these concerns can be addressed by using the FERC definition of "useful thermal energy" in its regulations mandating the minimum efficiencies of a QF, as recommended by EPUC/CAC. More specifically, FERC defines a cogeneration facility as "equipment used to produce electric energy and forms of useful thermal energy (such as heat or steam)." The regulations also define "useful thermal energy" as:

> "(h) Useful thermal energy output of a topping-cycle cogeneration facility means the thermal energy:
>
> > "(1) That is made available to an industrial or commercial process (net of any heat contained in condensate return and/or makeup water);
> >
> > "(2) That is used in a heating application (e.g., space heating, domestic hot water heating); or
> >
> > "(3) That is used in a space cooling application (i.e., thermal energy used by an absorption chiller)."[130]

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[130] 18 CFR §202(h). FERC regulations also refer to "useful thermal energy" in defining bottoming cycle cogeneration facilities as follows: "Bottoming-cycle cogeneration

Footnote continued on next page

By defining useful thermal energy in terms of its application to a productive industrial process, we concur with EPUC/CAC's observation that the FERC definition of "useful thermal energy output" includes only the thermal energy that is actually intended to be delivered to the thermal host (or in the case of bottoming-cycle cogeneration, first applied to the thermal application or process), and not any remaining thermal energy intended to be exhausted as waste heat. Moreover, it is also consistent with the plain meaning of "useful" that the FERC definition of "useful thermal energy" requires losses from converting available thermal energy into useful work to be taken into consideration when estimating/computing that value. Accordingly, in our rules we will clarify that the BTU THERMAL OUTPUT (expressed in kWh) in the adopted Conversion Method formula represents "useful thermal energy" output as defined in the FERC regulations implementing QF policy under PURPA.

We also find EPUC/CAC's recommendation on how best to document the useful thermal energy output of cogeneration facilities at the EPS "gateway screen" to be reasonable and workable. Specifically, EPUC/CAC recommends that we take advantage of the existing documentation requirements of cogeneration facilities, noting that they are required to complete a questionnaire on an annual basis to demonstrate compliance with FERC efficiency requirements. On this form, the cogenerator presents monthly and annual values for energy input (therms), useful power output (kWh), and useful thermal

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facility means a cogeneration facility in which the energy input to the system is first applied to a *useful thermal energy* application or process, and at least some of the reject heat emerging from the application or process is then used for power production. (18 CFR 292.202(e), emphasis added.)

energy output (MMBtu).[131] For the purpose of the interim EPS, we will calculate a cogenerator's emission rates using the values presented in these questionnaires, which are readily available from the interconnected utility. For new cogeneration facilities, when this questionnaire has not been submitted to the utility, the emissions rate calculation will be based on readily available energy input, useful power output and useful thermal energy output information in FERC Form 556, required for QF certification.

We emphasize, however, that the above approach for calculating and documenting cogeneration emissions rates is adopted for the limited purpose of demonstrating compliance with the interim EPS. Our determinations today are in no way intended to prejudge or predetermine the approach to be established in the context of our Procurement Incentive Framework or under the statewide GHG emissions limit envisioned under AB 32.

4.10. Emissions Rates for Renewables

In the draft report, staff recommended that all renewables, including those from biogenic sources, be assigned an emissions rate of zero. Staff recommended this approach after considering EPS goals, including administrative ease, as well as the data presented in comments on the net emission rates of various renewable technologies.[132] In the final report, staff modifies this recommendation pointing to the statutory language of § 8341(d)(4), which states:

> "In calculating the emissions of greenhouse gases by facilities generating electricity from biomass, biogas, or landfill gas energy,

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[131] See *Reply Comments of EPUC/CAC on the Final Workshop Report*, October 27, 2006. A copy of this questionnaire is attached.

[132] *Draft Workshop Report*, p. 29.

> the commission shall consider net emissions from the process of growing, processing and generating the electricity from the fuel source."

Based on the language of this section, staff concludes that any long-term commitment to renewables should "appear at the gate and file their applicable net emissions rate" before the Commission.[133]

All parties commenting on this issue disagree with staff's amended recommendations. They generally argue that SB 1368 provides the Commission with flexibility to make upfront determinations regarding the emission rates of renewables, and to find them compliant with the EPS based on those determinations. NRDC, TURN, UCS, WRA, SDG&E, SoCalGas, and PG&E point to the extensive analysis presented by GPI in its Phase 1 comments that, in their view, supports the following findings:

1) Many renewable generating sources operate without producing any GHG emissions at all, or levels of emissions much lower than the best available CCGT. This group of renewables includes geothermal, solar and wind.
2) Even without re-injection, the highest GHG emitting geothermal generators emit less than 100 lb (CO_2 equivalent/MWh, which is a fraction of the GHGs emitted by the most efficient CCGTs,
3) Solar thermal generators with full gas assist (up to 25 percent gas heat input) produce approximately 375 (CO_2 equiv) lb/MWh, still less than half the amount emitted by the most efficient CCGTs, and
4) When net emissions are accounted for, as required under SB 1368, generating electricity from biomass, biogas or landfill

[133] *Final Workshop Report*, p. 36.

> gas energy actually *reduces* the net GHG emissions associated with the disposal of society's waste and residue materials.

Attachment 6 summarizes the GHG emissions data filed by GPI. No party disputes the data or the conclusions drawn from it, as summarized above. Based on the record on net emission rates of renewables, GPI, NRDC, TURN, UCS, WRA, SDG&E/SoCalGas, LS Power Generation (LS Power) and PG&E recommend that the Commission make a one-time determination in Phase 1 that renewables comply with the EPS.[134]

IEP generally concurs with this position, but presents an alternate recommendation for biogenic-based renewable technologies. IEP suggests that the Commission adopt a pre-established calculation of net GHG emissions for each type of biogenic-based renewable technology that is likely to be subject to the EPS. These pre-approved emission calculations would then be used by the LSE when seeking approval for such projects.

We agree with GPI, NRDC, TURN and others that requiring the LSE to demonstrate compliance with the EPS for each and every long-term commitment with a baseload renewable resource would not further our policy objectives or those of the Legislature. Those stated objectives recognize that renewable resources are valued as being both environmentally and economically sound in the context of addressing the adverse consequences of climate change on the economy, health and environment of California.[135] In fact, SB 1368 echoes the policy expressed in the Energy Action Plan II that renewables (along with energy

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[134] PG&E and LS Power would also extend this upfront approval to renewable resources firmed by a non-renewable resource. We address this separate issue in Section 4.7, where we consider the treatment of contracts with multiple resources or facilities.

[135] See SB 1368, Sections 1 (a)-(c), and also GHG Policy Statement, pp. 1-2.

efficiency) are to be used to satisfy increasing energy and capacity needs *before* LSEs turn to fossil-fired generation.[136]

It is therefore fully consistent with these objectives to consider the approach recommended by these parties, that is, to issue an upfront finding in today's decision that renewable resources comply with the EPS. Moreover, if the record clearly demonstrates that these resources will pass the standard on a net emissions basis, it would be redundant and costly to require that LSEs demonstrate EPS compliance for each new ownership investment, new contract or renewed contract with renewables. Therefore, the general approach suggested by GPI and others would also enable us to reduce those costs, thereby reducing overall costs to electricity customers as well.

In its final report, staff expresses concern that SB 1368 may not permit the Commission to make an upfront one-time determination of EPS compliance for renewables. We find nothing in the statute that would preclude us from doing so. Section 8341(b)(1) directs that we shall not "approve" a long-term financial commitment by an electrical corporation "unless any baseload generation supplied under the long-term financial commitment complies" with the EPS. This language does not preclude us from determining, based on our consideration of these representative emission rates, that specific baseload resources or technologies have emissions well below the EPS and should therefore be pre-approved as EPS-compliant. In fact, §§ 8341 (b)(3) and 8341(d)(6) require that we "establish procedures" to implement the EPS, and in

[136] SB 1368, Section 1(d).

doing so, § 8341(d)(6) also directs us to consider the effects of the standard on "overall costs to electricity customers."

For the reasons stated above, we find that the approach for finding renewables compliant with the EPS recommended by GPI, NRDC and others is both consistent with the language and intent of SB 1368, as well as reasonable in light of overall cost considerations. However, based on the record in Phase 1, we cannot make a blanket determination today that *all* renewable resources or technologies are EPS-compliant, as these parties suggest. This is because the evaluation of net emissions presented on the record and discussed in parties' comments did not consider several types of renewable resources or technologies, including hydroelectric, fuel cells, photovoltaics, biodiesel, and ocean thermal systems.

Nonetheless, as illustrated in Figure 1, the record clearly supports a finding that the net GHG emissions from the following renewable resources/technologies meet the interim EPS:

- Solar Thermal Electric
- Wind
- Geothermal, with or without reinjection
- Generating facilities (e.g., agricultural and wood waste, landfill gas) using biomass that would otherwise be disposed of utilizing open burning, forest accumulation, landfill (uncontrolled, gas collection with flare, gas collection with engine), spreading or composting.

Consistent with the direction in SB 1368, the studies presented in the record calculated the emissions rates based on an evaluation of the net emissions resulting from the production of electricity.[137] In particular, for electricity generated from biomass, the studies considered the net emissions from "the process of growing, processing and generating the electricity from the fuel source," as directed under § 8341(d)(4). Appropriately, the calculations of net emissions considered both CO_2 and methane gases (on a CO_2 equivalent basis) to reflect the GHG emissions impacts associated with these processes.

The resulting calculations show that the net GHG emissions produced from the resources and technologies listed above are either zero, significantly less than today's adopted interim EPS standard, or even result in a net reduction in GHG emissions. This can be seen from the summary data presented in Attachment 6.

In particular, electric generation using biomass (e.g., agricultural and wood waste, landfill gas) that would otherwise be disposed of under a variety of conventional methods (such as open burning, forest accumulation, landfills, composting) results in a substantial *net reduction* in GHG emissions. This is because the usual disposal options for biomass wastes emit large quantities of methane gas, whereas the electricity production alternatives either burn the wastes that would become methane gas or burn the methane gas itself, generating CO_2. Since methane gas is some twenty-five times more potent as a

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[137] *Greenhouse-Gas Emissions From the Operation of Energy Facilities*, Pacific Institute Report, July 22, 1989 (Gleick, Morris and Norman); *Biomass Energy Production in California: The Case for a Biomass Policy Initiative*, November 2000, National Renewable Energy Laboratory Report No. NREL/SR-570-28805, (Morris), pp. 38-50. Summary data from these studies was submitted in GPI's July 27, 2006 post-workshop comments and the full text of the material referenced above was filed as attachments to the *Comments of the Green Power Institute on the Final Workshop* Report, dated October 18, 2006.

GHG than CO_2, and since the two gases have similar atmospheric residence times, trading off methane gas for CO_2 emissions from energy recovery operations leads to a net reduction of the greenhouse effect.[138]

The record fully supports an upfront determination that the renewable resources and technologies listed above are EPS-compliant. In practice, this means that an LSE does not have to demonstrate compliance with the EPS for any long-term financial commitments with baseload generation utilizing these renewable resources and technologies. Such commitments get an automatic "pass through the EPS screen" without requiring calculations to demonstrate that the net emissions rate is below the EPS, or requiring that the LSE wait for Commission approval of the proposed financial commitment, if such approval is required. (See Section 5 below).

4.11. Treatment of Null Renewable Power

There was considerable debate during workshops over how to attribute emissions factors to renewable resources that have sold off their renewable energy credits or "RECs." The term "null renewable power" refers to the power generated by those renewable resources that have transferred their renewable attributes through the trade or sale of RECs.

By way of background, the trading or sale of RECs provides a flexible compliance option to LSEs for meeting their RPS obligations, among other

[138] For the biomass technologies identified above, which utilize landfill gas, agricultural and wood waste as the biomass fuel source, by definition there are no emissions associated with growing the fuel. An LSE entering into a long-term financial commitment with a biomass generating project where the growing the fuel is required will need to calculate net emissions taking into account the emissions associated with "growing," as well as "processing and generating" the electricity from the fuel source pursuant to § 8341(d)(4).

potential purposes. By law, LSEs are required to meet a minimum percentage of their load through RPS-eligible renewable resources. More specifically, electricity generated from eligible renewable resources must equal at least 20% of the total electricity sold to retail customers in California per year by December 21, 2010.[139]

A simplified example of a REC trade is depicted in Figure 2, where Utility B is procuring 10 MWs of power generated from a renewable resource, but does not need that amount to meet its RPS requirement, so it sells off the RECs to Utility A. Now the RPS obligation is met by each service territory, even though more of the renewable generation is located in service territory B.[140] This example illustrates how the trading of RECs can serve to even out geographic disparities in where renewable development can occur.

In their written comments in Phase 1, some parties recommend that the Commission allow renewables to be treated as renewable power in terms of emissions profiles, regardless of REC status. Others recommend that the treatment of renewable power should require a transfer of all renewable attributes associated with the generation of electricity from the facility to the purchasing LSE. Under this approach, which staff supports, the resulting null renewable power would be considered an "unspecified" resource and treated the same as an unspecified contract for the purpose of imputing GHG emissions.

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[139] SB 107 (Stats. 2006, ch. 464).

[140] We recognize that this is a single, simplified example of how a REC trade would work, and that a future tradable REC system could apply to all RPS participants, generators and LSEs in the same service territory as well as different ones, and might be extended to allow non-RPS-obligated third parties, such as brokers, to buy and sell RECs.

Still others recommend that the Commission not consider this issue now, as the appropriate treatment will depend on how the REC market develops in California.

In considering this issue, we note that there is no regulatory REC market in California at this time.[141] We have identified the investigation of a tradable REC system as one of the tasks for R.06-02-012 and plan to initiate this investigation during 2007. This task will now necessarily include integration of the requirements of recently enacted SB 107 (Stats. 2006, ch. 464).[142] We therefore cannot predict at this time whether, how or when a REC market will develop in California. Therefore, there is some appeal to the suggestion of NRDC and others that we simply defer the issue of how to treat null power for the purpose of EPS-compliance in today's decision.

However, deferring our consideration of this issue would introduce considerable uncertainty with respect to the treatment of renewables, with a potentially dampening effect on the development of these resources. For example, it would create uncertainty over whether a baseload renewable generator will pass or fail the EPS screen when a contract comes up for renewal if that generator sells off RECs in the meantime. We do not believe it serves the purpose of this proceeding, or our consideration of a future REC market, to leave these types of questions unanswered.

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[141] As the Center for Resource Solutions described in their October 27, 2006 Reply Comments on the Final Report, there is a voluntary market for RECs that is used by municipal utilities in California to supply their green pricing customers and by REC marketers to sell RECS on the national market. However, this is not the regulatory REC market that this Commission addresses in its proceedings.

[142] See D.06-10-019 in R.06-02-012, pp. 33-36.

The fundamental issue we need to consider is this: Does it make sense to strip renewables of their GHG emissions attributes if RECs are sold when making the "go, no go" decision of whether an LSE can enter into a long-term financial commitment with that facility? We think the answer should be "no" for the following reasons.

First, stripping renewables of their emission profiles in this manner could easily create a "perverse" result in the context of EPS compliance, namely, it could discourage long-term commitments with renewable generators that have zero, low or even negative net GHG emission profiles in favor of resources with higher emissions rates. In the example depicted in Figure 2**,** the transfer of RECs from Utility B to Utility A simply determines where the *power produced* by the renewable resource is counted to meet RPS obligations. However, those desirable GHG emission profiles do not physically disappear from the facility with the transfer of the REC. The GHG emissions rate associated with the renewable facility under contract with Utility B continues to comply with the EPS, and renewing (or entering into a new) contract with that facility is preferable than entering into a long-term commitment with a baseload facility that may meet the EPS, but emits a higher level of GHGs than the renewable resource.

Moreover, in the context of EPS compliance, looking at the actual nature of the underlying powerplant even if RECs are sold does not create a double counting problem, as some parties suggest. This is because the EPS represents a "go-no go" standard for new long-term financial commitments separate from the RPS obligation to procure a minimum amount of electricity generation from EPS-eligible resources. As discussed above, each facility has to pass the EPS on its own emissions-generating merits, i.e., a high emitting facility would not be able to use a purchased REC for the purpose of reducing (or blending) its emissions to demonstrate compliance with the EPS. Therefore, there is nothing to double count here, since RECs would not have any value for EPS-compliance under our rules. Moreover, our treatment of RECs in the context of a "go-no go" EPS compliance determination is not inconsistent with § 399.12, as amended by SB 107, which provides that a REC "includes all renewable and environmental attributes associated with the *production* of electricity" (emphasis added), and not discrete investment decisions.

In contrast, in the context of an RPS program, the REC that is sold carries with it all the renewable attributes associated with the production of electricity so that another entity (LSE) can apply those attributes to meet its RPS obligations, which are also defined in terms of electricity production. In determining RPS compliance, double counting would occur if you let the REC "seller" also count those attributes towards its own RPS compliance.[143] If, down the road, RECs or similar instruments become tradable offsets for the purpose of meeting GHG emissions limits, then we will need to be very careful of potential double counting—just as we will for using tradable RECs to meet RPS obligations. But in the context of the interim EPS, we do not observe a double counting problem associated with our proposed treatment of null renewable

[143] In determining RPS compliance, double counting would occur if the REC "seller" (Utility B in the simplified example presented in Figure 2) also counted those attributes towards its own RPS compliance, after selling the RECs to another entity (Utility A in the Figure 2 example).

power as long as RECs cannot be used to offset emissions for EPS-compliance purposes.[144]

Third, in the EPS-compliance context, stripping renewables of their renewable attributes with the sale of RECs would create an inconsistent treatment of RECs between LSE-owned and non-LSE owned baseload renewable generation. This is because, as discussed in Section 4.2.3.1 above, LSE-retained generation is not generally subject to the EPS. So, if an LSE currently owns a baseload renewable generator, or builds one and passes the EPS at the "new plant construction" review point, the emissions from that generator will never be subsequently reevaluated as "null renewable power" if the LSE sells off the associated RECs.[145] However, if a third-party (non-LSE) does the same, the renewable facility will be reexamined and under staff's proposal imputed with an unspecified power emissions profile when the renewal contract comes up.

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[144] The Center for Resource Solutions suggests in its comments that a double counting problem would arise in the context of the voluntary REC market in which green pricing customers buy RECs from (for example) a utility in California. In particular, they contend that if the REC were purchased from a facility that qualified for a mandate such as EPS based on being a zero emission facility, "the purchase of green pricing electricity would have no impact since it would have happened anyway." *Reply comments on final Workshop Report and Staff Recommendations Regarding the Greenhouse Gas Emissions Performance Standard of the Center For Resource Solutions*, October 27, 2006, p. 6. We fail to see how this represents a double counting problem since the voluntary purchasers of RECs are paying for the environmental benefits created by the *production* of renewable energy (not discrete investment decisions), and the RECs will still reflect those benefits as long as the facility continues to operate. In any event, as discussed above, today's adopted treatment of null renewable power does not result in double-counting problems for EPS-compliance or in a regulatory REC market, which is the focus of this Commission's consideration of REC-related issues.

[145] Unless the LSE makes the types of renovations to plant that fall under the "new ownership investment" discussed in Section 4.2.3.2 above.

Thus, the staff proposal could result in the emissions from two identical renewable baseload generators that sell off their RECs being valued very differently, depending upon who owns the generator.

Finally, as discussed at length in Section 4.12, there are considerable downsides to any approach presented in this proceeding for imputing emission factors to system purchases/unspecified power contracts. Even if we were inclined to impute null renewable power with something other than the facility's actual emissions, which we are not, we lack a reasonable method for doing so.

For all the reasons stated above, in applying the interim EPS we adopt today, the emissions of a renewable facility will not change if or when it sells RECs under a future regulatory REC market. Nor will RECs count towards compliance with the interim EPS by those LSEs who may purchase them for RPS compliance purposes in the future. However, we emphasize that today's determination on how to treat null renewable power and associated RECs is specific to the application of today's adopted interim EPS. This determination in no way guarantees that null renewable power will be assigned a zero or low GHG emissions value in the context of the Procurement Incentive Framework we are implementing in Phase 2 of this proceeding, or the statewide GHG emissions limits adopted by the Legislature in AB 32.

4.12. Consideration of Unspecified Contracts

The staff workshop report defines "unspecified contracts" as those contracts/power purchases that are not linked to any particular generating source, although in some instances the type of fuel or heat rate (Btus/kWh) of the contract may be specified. There was considerable debate during Phase 1 over whether to impute a specific emissions rate to unspecified contracts and, if so, what proxy rate to utilize for this purpose. The following approaches for imputing emissions rates were considered and discussed during the workshop process and in written comments:

a) Western Energy Coordinating Council (WECC) system average: Incorporates all generation activities throughout the western region.

b) WECC geographic average: Computes an emissions factor for all generation activities in various regions of the WECC system such as the Northwest, Southwest, etc.

c) CEC calculated "California Net System Power Average" or "California Net Power Mix": Represents the sources (e.g., coal, large hydroelectric, natural gas, nuclear, renewables) of electricity generated in California or imported to serve California customers that no retailer has identified through voluntary disclosure of specific purchases.

d) Coal emissions factor: would be based upon representative emissions from coal generation.

Below, we summarize staff's recommendations and the positions of the parties, followed by a discussion of our findings and conclusions.

4.12.1. Staff Recommendations

Based upon review of the data and parties comments, staff concludes that the WECC system average is generally not reflective of California activities or markets, and therefore should not be used to impute emissions rates for unspecified contracts. Staff rejects the use of WECC sub-regional geographic averages, since it would appear to penalize and reward LSEs differently based upon the major geographic source of their imported system power. Staff also rejects the use of coal as a proxy emissions factor, concluding that it is not an accurate reflection of the characteristics of all unspecified resources.

Staff recommends utilizing the California Net Power Mix information produced by the CEC as the basis for imputing GHG emission rates to unspecified contracts. This calculation sums all in-state generation and electricity imports by fuel type and subtracts from this total: 1) electricity procured by retailers (California investor-owned utilities, public power and electric service providers) that they reported as "specified purchases" to the CEC and 2) electricity generated in California for use on-site rather than for retail sales.

The net result is a California Net Power Mix label that presents the percentage of power by fuel type (coal, large hydroelectric, natural gas, nuclear, renewables).[146] While reporting of specific purchases is voluntary, in order to make a claim that its mix of power is different from the California Net Power Mix, the retailer must disclose specific power purchases to their customers and to the CEC. The amount of electricity that retailers have elected *not* to disclose to their customers and to CEC (defined as "net system power") has declined over time as specific-purchase reporting in California has increased: In 1998, net system power represented 98 percent of retail electricity sales, while in 2005 it was less than 30 percent of the total.

In presenting its recommendation, staff acknowledges the concern raised by some parties that LSEs will be inclined to enter into unspecified contracts with high emitting resources in order to circumvent the EPS by having a possible lower emissions rate imputed to that contract. However, staff anticipates that

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[146] For 2005, the California Net Power Mix calculated by the CEC was as follows: Coal-38.5%, Large Hydroelectric-23.5%, Natural Gas-33.3%, Nuclear-0% and Eligible Renewables-4.7%. Keep in mind that this is different from CEC's calculation of the "gross system power," i.e., the fuel mix serving California load. The percentages above only reflect the fuel type break-downs for power that was not specified by retailers in their voluntary reporting to the CEC.

this will not be a substantial issue based on its understanding that long-term contracts with unspecified resources are at most a small fraction of the incremental power supply. Moreover, staff states that it will "monitor contracting patterns and behaviors to ensure that they do not change for this reason."[147]

4.12.2. Positions of the Parties

SDG&E/SoCalGas support the concept of using the California Net System Mix to impute the emissions profile for unspecified contracts, but only if the refined methodology proposed by CEC staff in May 2006 for the calculation of net system power is utilized for this purpose, rather than the current one. They argue that the refined methodology is appropriate because it results in imputed emissions that will enable unspecified contracts to pass the EPS, whereas the current one will not.

In contrast, Calpine, Sempra, PG&E and SCE, NRDC, TURN, UCS, GPI and WRA generally object to the use of the California Net System Mix, albeit for somewhat different reasons. NRDC, TURN, UCS and WRA argue that relying on any averaged emissions rate is problematic because it: 1) provides no information or guidance on the critical distinctions between emissions from different types of generating units, 2) invariably dilutes the emissions rates of the higher emitting sources and 3) could provide a significant loophole if the average rate enables all unspecified contracts to automatically pass the EPS.

To address these shortcomings, NRDC, TURN, UCS and WRA recommended in post-workshop comments and comments on the draft report

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[147] *Final Staff Report*, p. 38.

that the Commission assign unspecified resource contracts the emissions level of a conventional pulverized coal generator. In their comments on the final report, these parties indicate that they are willing to support the use of the CEC Net Power Mix to calculate the emissions associated with unspecified contracts if the highest emissions rate for each fuel type is used in that calculation. Using the current 2005 California Net Power Mix, NRDC calculates that the result would be a weighted average emissions rate of 1,668 lbs CO_2/MWh.

PG&E objects to using the California Net Power Mix, arguing that doing so has the potential to penalize or remove from California's resource mix system purchases that are otherwise clean, such as system imports from the Northwest. PG&E recommends that the Commission defer adopting a specific methodology for imputing GHG emissions from unspecified contracts until it can consider a more precise methodology, perhaps through a follow-up implementation workshop.

Sempra and Calpine argue that using any proxy for imputing emissions rates to unspecified contracts would not be consistent with the Commission's goals or SB 1368. Although long-term commitments may currently make-up only a small fraction of the incremental power supply, Calpine and Sempra submit that the use of a proxy that would assign a lower emissions level to a resource could encourage long-term commitments with resources that would otherwise not meet the interim EPS limit. To address unspecified contracts in a manner that is consistent with SB 1368, these parties recommend that the Commission require that all long-term commitments for baseload generation be made with "specified resources" that can demonstrate compliance with the interim EPS.

GPI supports the position of Sempra and Calpine. In GPI's view, their recommended approach avoids the potential precedent-setting effect any alternative treatment of unspecified power may have for the design of the state's long-term AB 32 greenhouse gas program.

SCE opposes both the use of the California Net Power Mix as well as the recommendation of Sempra and Constellation. In SCE's view, the former represents an arbitrary method to determine whether such contracts should pass the EPS, and the latter fails to recognize that energy contracts without an upfront specified source are common transactions in the energy market today.

Instead, SCE recommends that LSEs be permitted to enter into a contract with a supplier with unspecified resources or facilities, and to provide documentation that shows the average emissions factor of that group of resources or facilities is lower than the rate used to impute emissions for unspecified contracts. If a system purchase is made, SCE recommends that this rate be based on the emissions of the system from which the purchase is being made, not the California Net System Mix. In the alternative, SCE recommends that the rate be based on the "default factor" used by the California Climate Action Registry (Registry) for calculating GHG emissions from the use of electricity. According to SCE, this factor is the average carbon intensity factor for the WECC California region, which is currently reflects "the average for Year 2000 egrid generators located in California, including imported energy."[148]

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[148] *Opening Comments of SCE on Final Staff Workshop Report and Proposal*, October 18, 2006, p. 11. See also *Reply Comments of SCE on the Final Staff Workshop Report*, October 27, 2006, pp. 10-11.

4.12.3. Discussion

SB 1368 provides the following general guidance on the issue of how to address unspecified contracts:

> "In developing and implementing the greenhouse gases emission performance standard, the commission shall address long-term purchases of electricity from unspecified sources in a manner consistent with this chapter."[149]

Based on the plain language of the statute, we believe this requires us to address unspecified contracts in a manner that ensures the following:

> (1) LSEs only enter into long-term financial commitments with baseload generation that comply with the EPS, and
>
> (2) EPS compliance cannot be achieved in a manner that would yield a contrary result, i.e., that permits an LSE to enter into long-term commitments with high-emitting sources.

Based on the record in this proceeding, we conclude that these objectives cannot be accomplished using an approach that imputes emissions rates to unspecified contracts, for several reasons. First, we have difficulty reconciling the concept of imputed emissions rates with the requirements of SB 1368 since, by definition, such proxies do not reflect the actual emissions from a resource. As a result, using imputed rates does not permit us to determine whether a commitment with an unspecified resource is consistent with the Commission's goals or SB 1368 or simply exacerbates the problems the Commission and the Legislature are trying to address.

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[149] § 8341(d)(7). We find no further discussion of unspecified contracts in the statute or legislative history.

Moreover, any method to impute a GHG emissions rate to unspecified resources results in a binary outcome in the context of an EPS—that is, all financial commitments with unspecified resources will either "pass" or "fail" based on the selected level of imputed emissions. As a result, there is enormous pressure to game the methodology and input assumptions used for this purpose, thereby making it very difficult and contentious to implement this particular approach to addressing unspecified contracts.

Not surprisingly, parties have generally lined up behind this issue based on whether they want "all" unspecified contracts to pass the EPS screen or "none" of them to pass. For example, NRDC originally proposed that the emissions of pulverized coal plants be used to impute emissions for unspecified contracts, an approach that would clearly result in none of them passing the EPS screen. NRDC now indicates qualified support for using the California Net Power Mix, but only if the very highest emission rates for each technology is utilized. By NRDC's own calculation, this would have the same result: None of the unspecified contracts would pass the EPS screen.

On the other hand, SoCalGas and SDG&E support the use of the California Net Power Mix, but only if the revised version under consideration by the CEC staff is used. When coupled with mid-range emission rates for each technology, this approach would permit all unspecified contracts to pass the EPS screen.

As DRA illustrates at some length in its comments, there are also various input assumptions associated with calculating an imputed emissions value using any proxy resource mix (California Net Power Mix, WECC system purchases, or others) that could be manipulated to "push" an unspecified contract through the

EPS gateway, such as the use of full load heat rates versus heat rate ranges under less than full-load conditions.[150]

SCE's recommendation also has the potential to push an unspecified contract through the EPS gateway, since the proposed default rates are based on broad geographic averages that would permit high emitting resources to pass the standard. Moreover, under SCE's proposal, the case-by-case review would be one-sided: The Commission would be asked to grant an exception to the imputed emissions value only in those instances where the power is being purchased from a group of very low emitting resources (e.g., a group of all hydroelectric power plants), but not when the opposite may be true.

Finally, none of the specific proxy approaches recommended by staff or in parties' comments are reasonable or workable for our purposes, at least not at this time. As staff points out, the WECC system average is generally not reflective of California activities or markets, and the use of WECC sub-regional geographic averages would also dilute the impact of high-emitting resources, allowing them to automatically pass through the GHG screen. Similarly, the WECC California region average metric suggested by SCE in its October 18, 2006 comments represents a broad statewide average that does not distinguish among different types of generating resources on the basis of their relative GHG emissions. It is also too broad a metric for the purpose of establishing whether an unspecified contract is EPS-compliant or not.

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[150] *Opening Comments and Legal Argument of the Division of Ratepayer Advocates on the Final Workshop Report on Phase 1 Issues*, October 18, 2006, pp. 5-7. As DRA points out, under less than full-load conditions, one can expect the corresponding heat rates to go up, and therefore result in higher emission values.

As discussed above, staff and some parties propose that we utilize the California Net Power Mix as a proxy for the resource mix associated with unspecified contracts for the purpose of evaluating EPS-compliance. We note that this mix was developed by the CEC for a very different purpose (power content labeling), and has not been revised, updated or endorsed by the CEC for use in imputing GHG emissions under SB 1368 or in any other GHG emissions policy context.

Moreover, there is no clear conceptual link between this metric and the mix of resources that might underlie unspecified contracts now or in the future, even on a system-wide average basis. The calculation is based on what is left over after the amounts that retailers voluntarily report as the resources underlying their short- and long-term power purchases (and accounting for on-site generation). It was developed to encourage retailers to disclose their actual power mix to customers. For that purpose, the CEC reports that power content labeling has been successful since the amount of net system (unreported) power has decreased significantly since its inception. Nonetheless, we do not find a reasonable conceptual correlation between this metric and the resource mix that might underlie unspecified long-term contracts.

For the reasons discussed above, we find that adopting an approach to unspecified contracts that involves the use of proxy estimates for emission rates would not further the goals of SB 1368 and would be problematic from an implementation standpoint.

That brings us to the approach recommended by Sempra and Calpine, namely, to require under our rules that all long-term commitments for baseload generation be made with "specified resources" that can demonstrate compliance with the interim EPS. This approach is fully consistent with SB 1368 since it ensures that "any" and "all" long-term financial commitments with baseload generation will meet the EPS, as the statute so directs.[151] Moreover, it cannot be gamed in a manner that could result in the opposite result than the statute intended, i.e., an increasing number of long-term commitments to high emitting resources. Although SCE argues that this approach would deprive LSEs of needed flexibility in resource procurement, thereby increasing costs to ratepayers, this assertion is simply not supported by the record.

Throughout the workshop process, attendees indicated that the LSEs would be entering into very few, if any, new contracts or contract renewals with unspecified contracts with a term of five years or greater. At the assigned ALJ's direction, SCE, SDG&E and PG&E submitted data on how many contracts of five years or more for unspecified power they (1) actually entered into during 2004 and 2005 and (2) planned to enter into over the 2006-2008 period. These utilities also provided data on the amount of unspecified power they have purchased and plan to purchase under short- term contracts (less than five years).

All three utilities responded that they did not enter into any contracts of five years or more for unspecified resources in 2004 and 2005, and do not anticipate entering into any contracts with unspecified resources with a term of five years or more in the 2006-2008 period. In contrast, all three utilities entered into numerous contracts with *short-term* unspecified contracts during 2004-2005, which is to be expected given the type of energy products offered under them.[152]

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[151] Indeed, it could be difficult in the case of an "unspecified contract" even to devermine whether any "baseload" powerplant is being used to generate the power.

[152] "Contracts with unspecified resources are for energy products whose offered prices are valid for a very short period of time. This is due to the fact that energy prices fluctuate constantly, in part due to fluctuations in commodity prices of natural gas as

Footnote continued on next page

In sum, the record shows that it is highly unlikely that the LSEs will be entering into any new or renewal power purchase contracts of five years or greater that are unspecified during the transition to a statewide GHG emissions limit. Therefore, requiring all long-term contracts with baseload generation be "specified" in order to demonstrate EPS compliance should not have a significant, if any, impact on an LSE's resource procurement flexibility.[153] Moreover, it is our understanding from consultations with the ISO staff that for the ISO's system reliability determinations, the ISO relies on specific information about the plant facility and its location within the ISO control area. Therefore, the requirement to specify the resources underlying long-term contracts for the purpose of demonstrating EPS compliance is consistent with the type of information that the ISO also requires for these reliability determinations.

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well as underlying market conditions. SCE has to decide whether to buy or not to buy such energy products in a very short period of time…. As a result, SCE is currently limited to soliciting contracts of energy products, including such contracts with unspecified resources, to those with durations less than five years consistent with its current procurement authority." See *SCE Greenhouse Gas Emission Standards Data Response*, October 18, 2006, Response to Question 03, posted at http://www.cpuc.ca.gov/static/energy/electric/climate+change/.

[153] During our interagency consultations on SB 1368, CEC staff has indicated that the publicly owned electric utilities may not be similarly situated, i.e., they have entered into a significant amount of contracts of five years or greater with unspecified power in recent years and may be planning to do so in the future. Nothing in today's decision is intended to suggest that the CEC may not consider unique circumstances facing these entities with respect to how an EPS that will apply to them should address unspecified contracts. However, we believe that the policy, legal and implementation issues associated with imputing emission rates to unspecified contracts discussed in today's decision will need to be carefully considered as the CEC develops an EPS that is consistent with the statute as well as today's adopted EPS, as directed by SB 1368.

A requirement that long-term power purchase contracts specify the underlying generation facilities is also consistent with our discussion of emissions registration in D.06-02-032 and represents a logical interim step towards the implementation of AB 32.[154] Under that new law, CARB is required to establish the state's mandatory GHG reporting and verification program by January 1, 2008. At that point, all power contracts will need to provide verifiable GHG emissions documentation. To permit LSEs to enter into new or renewed long-term unspecified contracts with high GHG-emitting facilities through the use of an imputed emissions value for system power in the meantime could put them, and their customers, in a vulnerable position when these reporting requirements take effect in 2008 for the implementation of the statewide, load-based GHG emissions limits.

As Sempra points out, other jurisdictions have developed specific resource tagging mechanisms to track generation attributes, including GHG emissions, of resources within their control areas.[155] In particular, PJM Interconnection utilizes the Generation Attribute Tracking System and ISO New England utilizes the Generation Information System for this purpose.[156] In addition, the CEC has under development the Western Renewable Energy Generation Information System for purposes of tracking compliance with California's RPS statute. In our

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[154] D.06-02-032, pp. 47-48.

[155] *Comments of Sempra Global on Draft Workshop Report*, September 8, 2006, p. 6.

[156] PJM Interconnection is the regional organization that monitors and coordinates movement of wholesale electricity over a 56,000-mile section of the power transmission grid that spans across 13 northeastern and midwestern states and the District of Columbia. ISO New England serves similar functions across all of the New England states as the California ISO.

view, it is entirely feasible to implement a program that tracks the GHG emissions of all generating units, and that would enable marketers and other sellers of unspecified resource contracts to assign a reasonable and accurate GHG emissions profile to their contracts. Over time, this should be the strategy pursued by California to deal with emissions from any unspecified resource contracts that LSEs may wish to pursue; however, as the record shows, this is not a likely pursuit for the types of LSE long-term procurements subject to the EPS.

For the reasons discussed above, we will require that all long-term commitments be with specified sources in order to demonstrate EPS compliance (or that compliance is not required). As discussed in Section 4.8.5, in the event that an LSE must enter into a long-term unspecified contract to address system reliability concerns, it may request Commission consideration of a reliability exemption, on a case-by-case basis.

5. Compliance-Related Issues

The concept of a "gateway screen" approach to EPS compliance is an integral component of staff's recommendations and is supported by all parties. Under this approach, a series of questions or criteria are applied to first determine whether or not the LSE's financial commitment is a "covered procurement" subject to the EPS. If it is, then the commitment is screened to ensure that the associated GHG emissions rate does not exceed the adopted EPS performance level of 1,000 lbs of CO_2 per MWh. Once the financial commitment successfully passes through the gateway screen, the LSE has demonstrated EPS compliance for that particular commitment. Ongoing Commission review or monitoring of the facilities underlying that commitment is not required.

We adopt this approach for demonstrating compliance with the interim EPS. We believe it is consistent with the intent of SB 1368, which directs us to look to the "design and the intended use" of the powerplant under § 8340(a). Moreover, as staff and the parties point out, a gateway screen approach is the most practicable and enforceable manner in which to determine EPS compliance.

While parties agree on the concept of a gateway screen approach to determining EPS compliance, there is some disagreement on what compliance submittals should be required of different types of LSEs (i.e., large electrical corporations, small electrical corporations, energy service providers, community choice aggregators), as well as what documentation those submittals should contain. There is also disagreement among some parties on how to interpret SB 1368 with respect to alternative compliance for multi-jurisdictional utilities. In addition, clarification to the definition of "capacity factor" has been requested by some parties for compliance purposes. The final report does not provide specific recommendations on these issues.

Finally, there is disagreement among parties over whether offsets or other compliance options (such as "portfolio averaging") are appropriate for an interim EPS. We address these and other compliance-related issues below.

5.1. Compliance Process for PG&E, SDG&E and SCE

Parties commenting on this issue recognize that the Commission requires the largest electrical corporations (i.e., SCE, PG&E and SDG&E) to file long-term procurement plans for review and approval by the Commission pursuant to § 454.5, and also requires SCE, PG&E and SDG&E to seek Commission pre-approval before they can enter into procurement contracts of five years or longer.[157] There is consensus among the parties that the same procedural vehicles used by these LSEs to seek Commission pre-approval of their long-term procurement contracts should be used to seek pre-approval of covered commitments under the EPS rule we establish today. We agree, and outline those procedures below.

SCE, PG&E and SDG&E currently bring all power purchase contracts with terms of five years or longer before the Commission for review and pre-approval by filing either an advice letter (for RPS-contracts) or an application (for non-RPS contracts). For all RPS contracts, we use the advice letter process established in our RPS proceeding to pre-approve those procurements.[158] Each advice letter is reviewed by Energy Division, and a Commission resolution addressing the RPS contract is prepared for Commission approval. Under existing procurement rules adopted in D.04-12-048, PG&E, SCE and SDG&E file applications requesting Commission review and pre-approval of all non-RPS contracts with a term of five years or more. The Commission issues a decision addressing the applications.

We will use these existing procedural vehicles for reviewing and pre-approving PG&E, SCE and SDG&E's covered procurements with respect to EPS compliance. As discussed in Section 4.2, "covered procurements" includes new and renewal contracts of five years or greater with baseload generation, LSE new

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[157] This section of the Public Utilities Code was added by AB 57 (Stats 2002, ch. 835), and applies to all electrical corporations. As provided for under § 454.5(i), electrical corporations serving less than 500,000 customers are exempt from this procurement plan review and approval process.

[158] See D.03-06-071, p. 39, issued in R.04-04-026, the predecessor to our current RPS proceeding, R.06-05-027.

investment in baseload generation (new construction) as well as major alterations to baseload facilities. For PG&E, SCE and SDG&E, each of the various types of covered procurements subject to the EPS will be reviewed and pre-approved through the advice letter process (for RPS resources) or application process (for non-RPS resources) described above.

More specifically, for covered procurements with RPS-eligible baseload generation, these utilities shall submit documentation to demonstrate compliance with the EPS through RPS advice letter filings. These advice letters shall be served on the service list in our RPS Rulemaking, R.06-05-027, or its successor proceeding. Should an application process be used for any particular RPS contract, or should the advice letter process set forth in D.03-06-071 be changed in whole or in part to an application process in the future, that process will automatically apply to the EPS compliance filings required of SCE, PG&E and SDG&E for RPS resources.[159]

For all non-RPS covered procurements, PG&E, SCE and SDG&E shall submit documentation to demonstrate compliance with the EPS through the non-RPS application process established by our procurement rules. This includes any request for a Commission finding of EPS-compliance for covered procurements that employ geological formation injection for CO_2 sequestration. These applications shall be served on the service list in our Long-Term Procurement Rulemaking, R.06-02-013, or its successor proceeding. The

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[159] However, if the RPS advice letter process set forth in D.03-06-071 is modified to include procedures whereby these advice letters may be "deemed approved," such procedures shall not apply for the purpose of establishing EPS compliance.

Commission's determination on these matters will address the compliance of the covered procurements with our EPS rules.

As discussed in this decision, any request for a reliability exemption or an exemption based on "extraordinary circumstances, catastrophic events, or threat of significant financial harm" will require Commission pre-approval. We direct SCE, PG&E and SDG&E to file such requests by application with service on the service list in both R.06-02-013 and this proceeding, or their successor proceedings. Any request for an extraordinary circumstances modification shall be filed as a petition for modification of this decision.

In addition, we require all LSEs to disclose in their compliance submittals any multiple contracts of less than five years with the same supplier, resource or facility. (See Section 5.5 below.) We direct SCE, SDG&E and PG&E to disclose this information in their Quarterly Procurement Plan Compliance Reports[160] that demonstrate compliance with all Commission procurement rules.

5.2. Compliance Process for Small Electrical Corporations, Electric Service Providers and Community Choice Aggregators

Currently, the Commission does not require electric service providers, community choice aggregators or the "small electrical corporations" (i.e., those other than PG&E, SCE and SDG&E) to submit procurement plans or apply for pre-approval of long-term procurement contracts. AReM, Constellation, Plumas-Sierra and others argue that such pre-approval requirements should not be established for these entities for the purpose of demonstrating EPS compliance.

[160] Pursuant to D.02-10-062.

Instead, they recommend that electric service providers, community choice aggregators and the small electrical corporations make a more simplified after-the-fact compliance showing. In particular, AReM recommends using the existing resource adequacy compliance submittal for this purpose, which SCE, PG&E, SDG&E, electric service providers and community choice aggregators are required to file annually as an Advice Letter.[161] PG&E, Sacramento Municipal Utility District, California Municipal Utilities Association, Northern California Power Agency and the Southern California Public Power Authority support this approach in their comments.

Specifically, AReM envisions a process whereby in most cases, the electric service provider would simply certify that it had not entered into any financial commitments during the previous year that are subject to the EPS. If it had entered into such commitments, the electric service provider would provide documentation to show that the commitment was in compliance with the EPS. Constellation also suggests that the electric service provider could be subject to an independent third-party audit if the Commission has any doubt that the electric service providers are forthcoming in their demonstrations.

NRDC/TURN/UCS and WRA object to relying on procedures that would allow for after-the-fact compliance submittals, as recommended by AReM and others. They argue that this approach is not consistent with SB 1368 or with the concept of an upfront gateway standard. In their view, allowing electric service

[161] Currently, the smaller electrical corporations (e.g., Plumas-Sierra) and multi-jurisdictional utilities (Sierra Pacific and PacifiCorp) are not required to demonstrate resource adequacy compliance at this Commission. The resource adequacy rules for these entities are being developed in Phase 2 of R.05-12-013. See *Assigned Commissioner's Ruling and Scoping Memo* in R.05-12-013, March 1, 2006, p. 4.

providers or other LSEs to show compliance after-the-fact would not offer the same protection to its customers and would open a significant loophole to compliance if in the end an electric service provider did enter into a long-term financial commitment that violated the performance standard. In their view the standard must be enforced on an upfront basis for all LSEs before any long-term commitments are made.[162]

We read § 8341(a) to mean that all LSEs must comply with the statute if they enter into any long-term financial commitment involving baseload generation, irrespective of whether (or how) this Commission reviews and approves such commitments. Subsections (1)-(6) of § 8341(b) describe a variety of things that the Commission shall or may do related to the implementation of the EPS program, none of which imposes a requirement on the Commission that it must pre- approve all long-term commitments made by the LSEs. Had it intended to make this requirement, the Legislature could have directed, for example, that no electrical corporation shall enter into a long-term financial commitment unless it is pre-approved by the Commission.

It did not do so. Instead, the language of subsection (1) states that "the Commission shall not approve a long-term financial commitment by an electrical corporation unless any baseload generation supplied under the long-term financial commitment complies with the greenhouse gases emission performance standard established by the commission…" We read this to mean that if the Commission does approve such commitments in the first place, which is the case

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[162] *Opening Comments/Legal Brief on Final Workshop Report and Staff Recommendations Regarding the GHG Performance Standard of NRDC/TURN/UCS/WRA*, October 18, 2006,

Footnote continued on next page

for the large investor-owned utilities in our procurement proceeding, we must make a determination that the commitment complies with the EPS.[163] Similarly, subsection (2) does not require that we review long-term financial commitments that are proposed to be entered into by an electric service provider or community choice aggregator, but only states that we "may" do so. Therefore, in adopting rules and procedures to ensure compliance with the EPS, pursuant to § 8341(b)(3), we have the flexibility under the statute to consider a range of procedural vehicles for use by those LSEs for whom we do not currently have a procurement pre-approval process in place.

With certain exceptions, we provide for "after-the-fact" EPS compliance submittals for electric service providers, community choice aggregators and small electrical corporations.[164] We concur with AReM, Constellation and others that EPS compliance procedures that do not require Commission pre-approval are appropriate for those LSEs who are not required to submit procurement plans or procurement contracts for pre-approval under current Commission procedures. We believe that the documentation and other requirements adopted today provide reasonable safeguards against the risks to ratepayers of potential

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pp. 15-16, and *Reply Comments on the Draft Workshop Report Regarding the GHG Performance Standard of NRDC/TURN/UCS/WRA*, September 15, 2006, p. 5.

[163] We may make that determination on a case-by-case basis requiring that the LSE present a showing for each individual commitment, or we may make a one-time, up front determination for specific resources or technologies, as we have today for certain renewable resource technologies.

[164] The multi-jurisdictional utilities with less than 75, 000 California retail customers that receive Commission approval of alternate compliance under § 8341(d)(9) will not need to demonstrate EPS compliance at the Commission, and therefore would not be required to file an Attestation Letter. See Section 5.3 below.

non-compliance by an LSE that files an after-the-fact compliance showing. At the same time, this approach avoids creating new pre-approval requirements and associated administrative complexity for the Commission's regulation of the procurement practices of these entities. Moreover, we note that we have already established procurement-related compliance procedures for electric service providers and community choice aggregators that are similar to what AReM and others now propose for demonstrating EPS compliance. We think that this approach is reasonable for the interim EPS, with the following qualifications.

First, we do not adopt the resource adequacy filing as referred to by AReM and others as the procedural vehicle for these submittals. This filing is a compliance submittal related to a one-year ahead capacity obligation, rather than a multi-year procurement obligation or rule. The Commission does not review any contracts in the resource adequacy filing process. Compliance is demonstrated through a template and through the obligation of the capacity resources to "show up" through real time at the California Independent System Operator. Therefore, we do not believe it is appropriate to include the EPS-compliance showing in this particular filing. Instead, electric service providers, community choice aggregators and electrical corporations other than SCE, PG&E and SDG&E will be required to file an annual Attestation Letter, due by February 15 of each year, attesting to the Commission that the financial commitments it has entered into during the prior calendar year are in compliance with the EPS.

Second, the Attestation Letter shall comply with all documentation requirements described in Section 5.5, and contain a certification, including the name and contact information for the LSE officer(s) certifying the following under penalty of perjury:

"(1) I have reviewed, or have caused to be reviewed, this compliance submittal.

"(2) Based on my knowledge, information, or belief, this compliance submittal does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements true.

"(3) Based on my knowledge, information, or belief, this compliance submittal contains all of the information required to be provided by Commission orders, rules, and regulations."

Third, the Attestation Letter shall be filed as an advice letter, subject to the Commission procedures governing advice letter filings, which include opportunity for protests and responses.[165] However, no Attestation Letter shall be "deemed approved" under those procedures.

The Energy Division shall review the advice letters and approve them if the attestation is in compliance with today's adopted interim EPS rules. Energy Division approval of the advice letter only means that the attestation is in compliance with these rules, and does not establish any other matters (e.g., it does not determine that particular plants are in actual compliance with the EPS or that financial commitments not fully disclosed in the attestation are in compliance with this decision). Electric service providers, community choice

165 See D.05-01-032, Appendix: Advice Letter Filing, Service, Suspension and Disposition. We are in the process of updating these procedures in R.98-07-038, and as indicated in Section 5.1 above, may also modify the advice letter process set forth in D.03-06-071 in the future. We recognize that some clarifications or modifications to procedures for the annual Attestation Letters and other advice letter compliance submittals adopted today may need to be made after the effective date of this decision in order to reconcile them with updated Commission procedures for advice letters in R.98-07-038 or R.06-05-027, or their successor proceedings. We delegate to the Assigned Commissioner the authority to make such clarifications or modifications by ruling or other manner, in consultation with the assigned ALJ and Energy Division.

aggregators and small electrical corporations shall be subject to penalties if the attestation letters are found, at a later date, to be incomplete, misleading or incorrect.

In addition, an electric service provider, community choice aggregator or small electrical corporation may submit an advice letter during the year requesting pre-approval of a new financial commitment as EPS compliant, at its discretion. All advice letter filings, as well as responses or protests, shall be served on the service list in this proceeding or its successor proceeding.[166] We caution electric service providers, community choice aggregators and small electrical corporations not to burden this process with requests for pre-approval of financial commitments that are clearly exempt from having to show EPS compliance, such as a single contract for a term of less than five years.

As discussed elsewhere in this decision, all LSEs are required to file (1) an application requesting Commission pre-approval for a reliability exemptions, (2) a petition for modification of this decision where the request is based on "extraordinary circumstances, catastrophic events, or threat of significant financial harm" or (3) an application for covered procurements that employ geological formation injection for CO_2 sequestration. Accordingly, the advice letter process described above will not be applicable to these types of requests. Instead, small electric corporations, electric service providers and community choice aggregators are required to file such requests by application or petition for modification, and serve them on the service list in this proceeding, or its successor proceeding.

[166] However, no such advice letter shall be "deemed approved."

5.3. Alternative Compliance Provisions for Multi-Jurisdictional Electrical Corporations

Under SB 1368, the Commission may consider a showing of "alternative compliance" by multi-jurisdictional electrical corporations that serve 75,000 or fewer retail end-use customers in California. Specifically, § 8341(d)(9) states that these LSEs:

> "…may file with the commission a proposal for alternative compliance with this section, which the commission may accept upon a showing by the electrical corporation of both of the following:
>
> > "(A) A majority of the electrical corporation's retail end-use customers for electric service are located outside of California.
> >
> > "(B) The emissions of greenhouse gases to generate electricity for the retail end-use customers of the electrical corporation are subject to a review by the utility regulatory commission of at least one other state in which the electrical corporation provides regulated retail electric service."

If the Commission approves a showing of alternative compliance, under § 8341(d)(9), then these utilities would not be required to demonstrate compliance at this Commission for their California operations pursuant to the procedures we adopt in Section 5.2 above.

The two multi-jurisdictional utilities subject to SB 1368, Sierra Pacific and PacifiCorp, both indicate in their comments that they will seek Commission approval of alternative compliance with the EPS, as provided for by § 8341(d)(9). They request clarification by the Commission in this decision as to what types of regulatory review would satisfy subsection (B).

More specifically, PacifiCorp suggests that we interpret step B to be satisfied when 1) a state jurisdiction requires a utility to review and report on the potential impacts of different carbon policies within its Integrated Resource Planning process; or 2) when it requires the utility to disclose its greenhouse gas emissions or expected change in overall emissions as a result of changes to its portfolio, including new capacity additions; or 3) when a state jurisdiction adopts rules specifically regulating emissions of greenhouse gases from electricity generating facilities.[167] PacifiCorp further states that "four of our six state commissions require PacifiCorp to consider greenhouse gas emissions in electricity resource planning."[168]

Citing the above three alternate tests, Sierra Pacific states that it believes its upcoming Integrated Resource Plan filing with the Public Utilities Commission of Nevada will meet two of these three tests and that it currently fits squarely within the alternative compliance approach contemplated in SB 1368.[169]

PacifiCorp argues that in order for it "to understand its compliance obligations, and especially in light of the fact that we are undertaking an update to our Integrated Resource Plan, we believe it is absolutely critical that the Commission provide as much certainty as to what is expected of multi-jurisdictional utilities in order to satisfy the second step of the two-part test."[170] Therefore, PacifiCorp urges us to pre-approve the types of review conducted by other state commissions that would qualify as "alternative compliance" with SB 1368.

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[167] *Opening Comments of PacifiCorp on Draft Staff Workshop Report*, September 8, 2006, p. 3.

[168] *Reply Comments of PacifiCorp on Final Staff Workshop Report*, October 27, 2006, p. 5.

[169] See *Opening Comments of Sierra Pacific Power Company on Final Staff Workshop Report,* October 18, 2006, pp. 3-4.

[170] *Reply Comments of PacifiCorp on Final Staff Workshop Report*, October 27, 2006, p. 4.

We agree with Sierra Pacific and PacifiCorp that we should now provide guidance as to how they can show alternative compliance, so as to facilitate their preparation of the resource plans that they will be presenting to several public utilities commissions. We see no reason to put this policy decision off for another day as suggested by NRDC.[171]

We also find PacifiCorp's three alternative compliance tests to be reasonable, and will adopt them. They closely track the statutory language and appear consistent with staff's final recommendations.

Finally, we must address how multi-jurisdictional utilities will make a showing that they comply with one of the above three tests and the other requirements of § 8341(d)(9). We conclude that the utility should file its proposal as an application with service on the service list in this proceeding, or its successor proceeding. Unless and until that application is approved by the Commission, all multi-jurisdictional utilities are required to submit annual Advice Letters demonstrating compliance with the EPS pursuant to the procedures discussed in Section 5.2 above. In addition to the information described in that section, the multi-jurisdictional utility's compliance filing shall describe the method used to identify and allocate its long-term financial commitments to California retail customer load.

5.4. Portfolio Averaging, Offsets and Other Proposed Compliance Options

CEED, LS Power and SCE argue that the interim EPS should include an offsets program, whereby the LSE would have the option to offset emissions from a high-emitting baseload resource with GHG emissions reductions secured

[171] *Opening Comments of NRDC on Final Staff Workshop Report*. October 18, 2006, p. 8.

elsewhere to bring it into EPS compliance. For this purpose, these parties advocate allowing offsets secured from industries other than just the electric generating sector and without geographic restrictions. They provide no specifics on how such an offsets program could be established and enforceable by the statutory deadline, but contend that allowing them would provide flexibility in meeting the goals of the EPS, spur broader innovation, and control costs.

For similar reasons, CEED advocates "portfolio averaging," although it is not clear from CEED's submittal what exactly that means in the context of an EPS applied on a commitment-by-commitment basis. Presumably, the Commission would look at a "portfolio" of long-term commitments made by the LSE over some period of time, and then assess EPS compliance with respect to the average emissions rate of that portfolio.

In its draft and final report, staff recommends that the Commission not include these types of compliance options because they would require significant upfront analysis and ongoing reporting and monitoring requirements, resulting in delays in both the implementation and enforcement of an interim EPS. For this and other reasons, Calpine, Constellation, IEP, NRDC, TURN, UCS and WRA do not support the use of offsets or portfolio averaging to comply with the EPS. In their view, such compliance options do not fit within the concept of an interim EPS and would serve to defeat its purpose.

We agree with staff and these parties that one reason to reject the compliance options proposed by CEED and others is that they cannot be designed and implemented within the timeframe contemplated for an interim EPS, particularly in light of the statutory requirement that an enforceable EPS be put in place no later than February 1, 2007. However, there is another, more fundamental reason to reject them: Allowing the LSE to use portfolio averaging or offsets to comply with the EPS would compromise the very purpose of establishing a GHG emissions-based standard in the first place.

As discussed throughout this decision, the interim EPS is intended to be a facility-based minimum performance standard governing long-term commitments made by an LSE to baseload generation facilities. This reflects a fundamentally different purpose, serving different policy objectives, than programs to reduce GHG emissions through a portfolio-wide cap, cap-and-trade programs or programs that permit LSE's to use offsets to meet an emissions cap or performance standard. The purpose of these programs is to provide varying degrees of compliance flexibility when the primary policy goal is to reduce the overall level of emissions generated through procurement activities.

In particular, portfolio-averaging permits an LSE to meet an emissions limit (or "cap") with a variety of short-term and long-term procurement combinations. For example, the LSE can procure electricity (build or purchase) on a long-term basis from a very high-emitting generating facility as long as it has other resources in its procurement portfolio that lower the average enough to meet the emissions cap from year-to-year. In other words, as long as the emissions associated with the LSE's overall procurement portfolio do not exceed the total number of allowances (permitted level of emissions) allocated to it, the LSE will be in compliance with the program.[172] Under a "cap-and-trade" program, the allowances allocated to the various LSEs subject to the cap can be

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[172] An "allowance" refers to a permit provided to the LSE within the scope of the emissions cap to emit one unit of emissions (e.g., tons of CO_2). The total number of available allowances reflect the total amount of permissible emissions, and usually decline over time. Allowances are allocated administratively or by auction to the entities subject to the cap.

traded. Thus, for example, the emissions of an LSE's procurement portfolio may exceed the number of allocated emission allowances if the LSE can purchase additional allowances from LSEs that do not need the number of allowances that they currently hold.

An offset program permits the LSE to make a reduction in emissions outside the scope of the emissions cap, which in turn allows an increase in emission levels associated with the LSE's procurement portfolio. The LSE can purchase offsets from third parties making investments to reduce emissions elsewhere (for example, investments in reforestation or in low-emissions vehicles or in the electric sector of other countries), or make those investments itself. This permits the LSE to exceed its allocated GHG emissions allowances. Under any of these compliance approaches to a GHG emissions cap, the LSE may enter into long-term financial commitments with high-emitting powerplants as long as it meets the level of the emissions cap for its portfolio as a whole, or acquires allowances and/or offsets to increase the permissible level of portfolio emissions.

In contrast, the interim EPS is aimed at ensuring that an LSE *does not enter into long-term financial commitments with high-emitting baseload resources in the first place.* This is because the primary objectives of the interim EPS is to ensure that there is no "backsliding" as California transitions to a statewide GHG emissions cap. This objective cannot be accomplished if LSEs are permitted to comply with the standard by diluting the emissions from non-compliant powerplants through portfolio averaging or increasing the permissible level of emissions for these powerplants (e.g., through offsets). These options would only disguise the types of problems that the EPS is designed to avoid, e.g., the high costs of future plant retrofits and reliability disruptions as it becomes increasingly difficult for these high-emitting facilities to comply with GHG emission regulations, such as the AB 32 declining cap on statewide GHG emissions.[173]

For these reasons, we do not adopt offsets or portfolio averaging in the context of today's adopted interim EPS. In the context of a load-based cap, however, we fully intend to evaluate a broad range of flexible compliance options as we proceed to implement the Procurement Incentive Framework during Phase 2 of this proceeding. Pursuant to AB 32, flexible compliance options will also be evaluated as California proceeds to implement the emissions limits required under that new law on a statewide basis.[174] As we stated in D.06-02-032, we will focus our efforts during Phase 2 on ensuring that the compliance options that we do permit under the Procurement Incentive Framework are credible, verifiable and administratively feasible. During Phase 2, we intend to carefully explore the pros and cons of alternate proposals for offsets, trading, banking and borrowing and other compliance options before making our final determinations. Throughout the process, we will closely coordinate with CARB, the Governor's Climate Action Team as well as other state, regional or federal agencies that are exploring design options for cap-and-trade programs.[175]

5.5. Documentation Requirements

In their compliance submittals, all LSEs should include a listing of the new long-term financial commitments of five years or longer they plan to enter into (SCE, PG&E and SDG&E) or have entered into during the prior year (electric

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[173] AB 32, § 38562(c).

[174] AB 32, § 38561, § 38570.

service providers, community choice aggregators, small electrical corporations) with documentation to demonstrate:

(a) That the commitments were not "covered procurements" under the interim EPS rule and/or

(b) For those that represent covered procurements, documentation demonstrating that such procurements are EPS-compliant.

(c) For any requested reliability-based exemptions that have been pre-approved by the Commission, a reference to the application and Commission decision number.

In addition, we require all LSEs to disclose in their compliance submittals any multiple contracts of less than five years with the same supplier, resource or facility. Disclosure of this information is necessary to ensure that LSEs do not circumvent the EPS rule by entering into a series of contracts with terms of less than five years with the same supplier, resource or facility. Such multiple contracts should be considered a single commitment and be reviewed as such (e.g., a contract for a three-year term link to a contract for the following three years must be seen as a single commitment of six years). Further, disclosure of LSE investments in retained generation, including "deemed-compliant" CCGTs, is also necessary to monitor compliance with the interim EPS rules. Therefore, we require all LSEs to disclose the investment amount and type of alteration to retained generation, by generation facility and unit. As discussed above, electric service providers, community choice aggregators and small electrical corporations will need to provide this information in their annual Attestation Letter. SCE, SDG&E and PG&E are required to disclose this information in their

[175] D.06-02-032, p. 44.

Quarterly Procurement Plan Compliance Reports[176] that demonstrate compliance with all Commission procurement rules.

As discussed in this decision, we permit case-by-case review of reliability exemptions and requests for modification based on extraordinary circumstances, catastrophic events, or threat of significant financial harm" due to circumstances unforeseen by SB 1368 and this decision, with the caveat that any consideration of such exemptions comes with a heavy burden of proof on the LSE. Any LSE requesting review and pre-approval of a reliability-based exemption from the EPS rule must provide documentation demonstrating that such long-term procurements are necessary to ensure system reliability. We caution all LSEs that they should not asked to be excused from the requirements of this decision for any other reason unless they can clearly demonstrate that: (1) they are facing extraordinary circumstances, catastrophic events or threat of significant financial harm not contemplated by SB 1368 and this decision, and (2) an exemption from some requirement of this decision is necessary to significantly mitigate or eliminate the challenges posed by these circumstances. These requests must be pre-approved by the Commission and shall be made by application in the case of a reliability exemption request, or petition for modification in the case of an "extraordinary circumstances" request, as discussed in Section 4.8.5.

We also require LSEs to file an application requesting a Commission finding of EPS-compliance for any covered procurement that employs geological formation injection for CO_2 sequestration. As part of this filing, the LSE shall provide documentation demonstrating that the geological formation injection

[176] Pursuant to D.02-10-062.

project has a reasonable and technically feasible plan that will result in a permanent sequestration of CO_2 once the project is operational.

Several parties have requested further guidance on the documentation required to determine whether a long-term financial commitment represents a commitment to baseload generation and if so, the associated emissions rate to use in evaluating EPS compliance.

We believe that the guidance provided in SB 1368 is instructive on this issue. Specifically, in determining whether a long-term financial commitment is for baseload generation, § 8341(b)(4) directs that we "consider the design of the powerplant and the intended use of the powerplant." This section goes on to enumerate several sources of information that are relevant for this purpose (e.g., the electricity purchase contract, any certification received from the CEC, any other permit or certificate necessary for the operation of the powerplant, any procurement approval decision). It also states that we may base our determination on "any other matter" that we find to be "relevant under the circumstances."

Accordingly, in their compliance filings, LSEs are advised to present documentation regarding the design and intended use of the powerplant(s) underlying their new long-term financial commitments utilizing the sources of information listed in § 8341(b)(4), as well as any other sources of documentation that they believe will be relevant to this determination. The key concept here is that the documentation should relate to establishing the design and intended use of the powerplant. As discussed in Section 5.6 below, documentation of the annualized plant capacity factor for the powerplant should include historical annual averages in order to determine whether the plant is "designed and intended" to be used for baseload generation.

We note that PG&E proposes demonstrating compliance with the EPS thorough "documentation of the facility's full load heat rate and expected capacity factor"[177] However as NRDC and others observe, the full load heat rate is the heat rate of a plant at full output and is not representative of the actual operations of a plant. Full load heat rates are lower than heat rates during actual plant operations, and therefore underestimate the heat rates and corresponding emissions of plants that are operating as "designed and intended."[178] Rather than assume full load heat rates, as PG&E proposes, LSEs should provide documentation of capacity factors, heat rates and corresponding emission rates that reflect the actual, expected operations of the plant.

5.6. Definition of Capacity Factor

In their opening comments on the final report, EPUC/CAC requests clarification of the definition of capacity factor to be used in the EPS baseload screen. They point out that SB 1368 defines baseload using the term "annualized plant capacity factor," whereas the staff report defines covered resources based on their "average annual" capacity factor. They suggest formally defining "annualized" as an "annual average." In particular, they propose that the capacity factor be calculated by summing the total annual energy "deliveries" of a resource, averaging them over the year, and then dividing that average by the plant's maximum permitted capacity.[179]

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[177] *Comments of PG&E on Draft Workshop Report*, September 8, 2006, p. 4.

[178] This is because as the plant output decreases, the corresponding heat rate (Btu/kWh) increases, and emissions are proportional to heat rate for the same fuel type.

[179] *Opening Comments of EPUC/CAC on the Final Workshop Report*, October 18, 2006, p. 11.

The Merriam-Webster Online Dictionary defines annualize as: "to calculate or adjust to reflect a rate based on a full year." We therefore find it reasonable to define the term "annualized" to mean "annual average" as EPUC/CAC suggest, but with a significant caveat. The annual average must be calculated in a manner that is consistent with today's decision, that is, it must be based on the annual production of the underlying facility, and not just what might be delivered under a specific contract with an LSE. As IEP points out, a strict interpretation of ECAC/CAC's proposed definition could result in partial year contracts being treated in a manner that conflicts with today's determinations.[180]

Moreover, there are likely to be situations where more than a single year of annual electricity production will need to be considered in determining whether or not a powerplant is "designed and intended" to provide electricity at an annualized plant capacity factor of at least 60 percent. (§ 8340(a).) In fact, the definition of "plant capacity factor" provides for our consideration of more than a single year, in that it expresses the capacity factor as a ratio of electricity produced to electricity production at rated capacity "during a given time period." (§ 8340(l).) This makes sense, because a plant's operations may vary significantly from year to year, based on weather or economic conditions. However, if it were designed and intended to operate as baseload generation, under the law it is subject to the EPS. Therefore, in their showing of whether the EPS applies to a new long-term financial commitment (other than new plant

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[180] See *Reply Comments and Legal Brief of the Independent Energy Producers Association on the Final Staff Workshop Report*, October 27, 2006, p. 5.

construction), LSEs should include historical plant capacity factors for the underlying facility or facilities to document the annualized plant capacity factor.

Consistent with the above and the definition of plant capacity factor provided in SB 1368, we clarify what is meant by "annualized plant capacity factor" as follows:

> "An annualized plant capacity factor is the ratio of the annual amount of electricity produced, measured in kilowatthours, divided by the annual amount of electricity the unit could have produced if it had been operated at its maximum permitted capacity, expressed in kilowatthours."

5.7. Long-Term Procurement Plans and the EPS

In our Long-Term Procurement Rulemaking (R.06-02-013), we directed SCE, PG&E and SDG&E to indicate in their long-term procurement plans (LTPPs) how they would comply with the EPS under consideration in this proceeding.[181] Within sixty (60) days from the effective date of this decision, SCE, PG&E and SDG&E should update their LTPP filings in compliance with the adopted EPS rules, as necessary, to reflect today's determinations. If changes to the LTPP filing are necessary to show compliance with this decision, SCE, PG&E and SDG&E should file an Amendment to the LTPP, Volume 1, indicating whether the Amendment supersedes or adds to specific sections of the plan, with service on the service list in R.06-02-013. If additional rules related to GHG policy are adopted in the future, in between the biennial review process, SCE, PG&E and SDG&E should update their LTPPs using the standard procedure for

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[181] *Assigned Commissioner's Ruling and Scoping Memo on the Long-Term Procurement Phase*, R.06-02-013, September 25, 2006, p. 24.

amending those plans, i.e., currently they can update LTPPs in between the biennial review process via an Advice Letter filing.

We note that the Phase 2 Scoping Memo in R.06-02-013 did not require electric service providers and community choice aggregators to file LTPPs at this time.[182] If that ruling changes for subsequent years of LTPP filings, then electric service providers and community choice aggregators will be required to include in their LTPPs how they plan on complying with the EPS rules.

5.8. Other Compliance-Related Issues

Today's decision provides direction to LSEs on how to submit their EPS compliance filings, and what information to include in them. The Commission, Assigned Commissioner, ALJ and/or Commission staff retain the right to data request any of the LSEs, including the electric service providers, community choice aggregators or small electrical corporations, to ask for any copies of contracts or procurement information that is deemed necessary to evaluate compliance with the EPS. Moreover, any LSE may be audited if the Commission or staff has any doubt that the LSE is forthcoming in its demonstration of EPS compliance.

This includes any information on related contracts that the Commission or its staff may deem relevant in determining whether the LSE is circumventing the EPS rule by entering into multiple contracts of less than five years duration.[183] This also includes any information on investments in retained generation,

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[182] *Ibid.*, p. 36.

[183] Other "slicing and dicing" concerns discussed during the workshop process and in the draft and final recommendations (see final report at page 102) have become moot with today's determinations on size exemptions and the treatment of partial contracts.

including deemed-compliant CCGTs, that the Commission or its staff may deem relevant in determining whether the LSE has complied with the interim EPS rules.

If any of the financial commitments entered into by LSEs appear to be out of compliance with the rules, the Commission may consider issuing an Order Instituting Investigation (OII) or take other appropriate action. If the Commission finds that the LSE did not comply with the EPS, the Commission will address the level of penalties in the OII proceeding or other procedural forum, as it deems appropriate.

In complying with today's requirements, any LSE that seeks confidentiality protection for data contained in its EPS-related submittals must follow the policies and procedures set forth in D.06-06-066.

6. Issues Raised by Parties Outside the Scope of Phase 1

Several parties raise issues in their comments that are outside the scope of Phase 1, which we mention briefly below.

Referencing § 8341(b)(6), Carson Hydrogen Power requests that we address policies to encourage "zero- or low-carbon generation resources" in this proceeding. Section 8341(b)(6) states:

> "A long-term financial commitment entered into through a zero- or low-carbon generating resource that is contracted for, on behalf of consumers of this state on a cost-of-service basis, shall be recoverable in rates, in a manner determined by the commission consistent with Section 380. The commission may, after a hearing, approve an increase from one-half to 1 percent in the return on investment by the third party entering into the contract with an electrical corporation with respect to investment in zero- or low-carbon generation resources authorized pursuant to this subdivision."

Commission overall policies addressing "zero- or low-carbon generation resources" are not within the scope of Phase 1. If an electrical corporation seeks Commission approval of a rate-of-return increase on investments made by third parties, as described in § 8341(b)(6), it may file such a request in our Long-Term Procurement Rulemaking (R.06-02-013), or its successor proceeding.

Calpine recommends that the Commission take additional steps to encourage long-term commitments with resources with emissions below the EPS limit, such as providing incentives to reward LSEs for contracting with lower emitting resources and resource owners for developing such resources. This recommendation is beyond the scope of Phase 1. In D.06-02-032, we discuss how we intend to pursue financial incentives for preferred resources in conjunction with a GHG emissions cap, and identified the resource-specific proceedings where such "shareholder risk/return incentive mechanisms" will be considered. We also discuss our intent to pursue the concept of "allowance sale incentives" for superior performance in GHG reductions during Phase 2 of this proceeding.[184]

Finally, in its post-workshop comments, San Francisco Community Power urges us to commit to a specific inventory of emission allowances on a date certain for each LSE, on a date certain (e.g., January 1, 2007). It would be premature, and beyond the scope of Phase 1, to establish target dates for these determinations in today's decision. The schedule for addressing this and other baseline-related issues for a load-based cap, including allowance allocations among individual LSEs, will be established during Phase 2 implementation of

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[184] D.06-02-032, pp. 30-32, 34-35.

our adopted Procurement Incentive Framework, in coordination with CARB and other state agencies implementing AB 32.

7. Federal Preemption Issues

In Section 4.8.3 above we address federal preemption arguments with respect to applying the EPS to QFs. In its Phase 1 legal brief, CEED raises a second federal preemption issue, namely whether adoption of the EPS conflicts with United States foreign policy.

CEED argues that "the President has articulated a federal policy of not mandating unilateral reductions in CO_2 emissions from United States sources because responsibility for committing to and implementing any binding emission controls to address global climate change must be shared by all nations, including developing nations. Moreover, Congress has endorsed the President's policy against requiring CO_2 emission reductions only from the United States and other developed countries."[185] However, the authorities they do cite (a letter and statements from the President and S. Res. 98, 105th Cong. (1997)) only establish, at most, a much less sweeping proposition concerning U.S. foreign policy: namely, that the United States has a foreign policy of not entering into treaties that do not require the curbing of $C0_2$ emissions from developing nations.[186] It is unclear how California, which is not proposing to sign any international agreement here, could be undermining such a policy. Ultimately, CEED's argument seems to be that because the President does not wish to do anything about climate change until he can get recalcitrant developing countries

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185 *CEED's Opening Brief on Jurisdictional and Other Legal Issues,* June 30, 2006, p. 10.

186 *Ibid.*, footnotes 23, 24 and 26.

to agree to curb their GHG emissions, that states are precluded from taking actions that can ameliorate the impacts of climate change on their citizens; because the President wants developing nations to do their share, therefore California cannot do its share. In short, we conclude that there is no conflict between California's adoption of an EPS and a federal foreign policy of not agreeing to international GHG treaties unless they include reductions by developing countries.[187]

In support of its argument, CEED cites to *Am. Ins. Ass'n* v. *Garamendi*, 539 U.S. 396 (2003) and *Hines* v. *Davidowitz*, 312 U.S. 52 (1941).[188] The situations in both of those cases are entirely different from the situation here. *Garamendi* involved a clear conflict between a state law and federal foreign policy expressed in an executive agreement that the President had entered into with foreign governments. Furthermore, the executive agreement concerned a matter traditionally within the scope of the President's federal foreign policy power. In addition, the state law was not in an area of traditional state jurisdiction. Indeed, the state law was aimed at insurance policies issued in Europe during the Holocaust era. *Hines* involved conflicting state and federal statutes for the registration of aliens. The Court in *Hines* recognized the treatment of aliens as being distinctly a matter handled by the federal government in the arena of international affairs. The state law was directed at foreign citizens and was

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[187] CEED's speculation that there might be some conflict in the future ignores the fact that if the U.S. does sign a GHG treaty or otherwise promulgate a GHG policy that is binding on the states, California will be required to bring its program into compliance if there is a conflict. *Ibid.,* p. 11.

[188] *Ibid*., p. 9, footnote 21.

thereby, like the situation in *Garamendi*, not in an area of traditional state jurisdiction.

Here, in contrast, there is no conflict between: (1) policy statements by the federal government that it does not intend to enter into treaties with foreign governments that would require the United States to reduce GHG emissions unless developing countries do so as well; and (2) California law requiring that new long-term financial commitments, by California-regulated entities, for the production of electricity to be consumed in California, meet a GHG emissions standard. Furthermore, the regulation of air emissions is not traditionally within the exclusive parameters of the president's foreign policy powers. On the other hand, states traditionally have authority to: (1) reduce emissions to protect their own populations; and (2) protect ratepayers of state-regulated utilities.

For the foregoing reasons we conclude that there is no conflict between SB 1368 and our implementation of it, on the one hand, and federal law or foreign policy on the other hand.

8. Commerce Clause Issues

The Commerce Clause states that: "Congress shall have [the] [p]ower … to regulate Commerce with foreign [n]ations, and among the several [s]tates."[189] The negative implication, or dormant aspect, of the Commerce Clause limits the ability of individual states to impede the flow of interstate commerce.[190] Dormant Commerce Clause doctrine consists of three analytical frameworks. First, a state rule that facially discriminates against other states in order to

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[189] U.S. Const. art. I, § 8, cls. 1, 3.

[190] *See, e.g., H. P. Hood & Sons, Inc.* v. *Du Mond* (1949) 336 U.S. 525, 533-36.

protect local economic interests will generally be found invalid.[191] Second, when a state rule does not facially discriminate against out-of-state economic interests, the *Pike* balancing test will be applied. Under *Pike*, a state enactment "will be upheld unless the burden imposed on such commerce is clearly excessive in relation to the putative local benefits."[192] Third, a state rule must not regulate extraterritorially.[193] The EPS does not run awry of any of these tests and is thus valid under the Commerce Clause.

8.1. Discriminatory Effect

Any party challenging the constitutional validity of a regulation under the dormant Commerce Clause bears the burden of demonstrating discrimination.[194] CEED argues that the EPS (which the Commission is now implementing under the provisions of SB 1368) has a discriminatory effect on interstate commerce that violates the dormant Commerce Clause.[195] Citing *City of Philadelphia* for the principle that: "[a] state cannot block imports from other states, nor exports from within its boundaries, without offending the Constitution,"[196] CEED argues that

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[191] *See, e.g., Oregon Waste Systems, Inc.* v. *Department of Environmental Quality of the State of Oregon* (1994) 511 U.S. 93, 100-101; *but see Maine* v. *Taylor* (1986) 477 U.S. 131, 151-52 (Supreme Court upheld a discriminatory rule that furthered legitimate state interests where there were no reasonable, nondiscriminatory alternatives).

[192] *Pike* v. *Bruce Church, Inc.* (1970) 397 U.S. 137, 142.

[193] *See, e.g., Healy* v. *Beer Institute* (1989) 491 U.S. 324, 336-37.

[194] *See Hughes* v. *Oklahoma* (1979) 441 U.S. 322, 336.

[195] *See, e.g., CEED's Opening Comments on Final Workshop Report,* October 18, 2006, p. 19. Similar Commerce Clause arguments were addressed in a related proceeding, D.06-06-071, "Order Denying Rehearing of Decision 06-02-032" (June 29, 2006).

[196] *See, e.g., CEED's Reply Brief on Jurisdictional and Other Legal Issues,* July 11, 2006, p. 4 (citing *City of Philadelphia* v. *New Jersey* (1970) 437 U.S. 617, 620.).

the proposed EPS is unconstitutional because it would severely limit the ability of out-of-state coal-fueled generation plants to export their electricity into California.[197]

The EPS is distinguishable from the statute in *City of Philadelphia* for two reasons. First, the statute in *City of Philadelphia* prevented certain products from entering New Jersey. Under the EPS, electricity generated from high-GHG emitters can still be sold to California under contracts of less than five years from an existing LSE-owned powerplant. The predominant limitation of the EPS is that until coal-fired baseload plants can meet the EPS, they cannot sign new or renewal contracts with a term of five years or more to supply California. In addition, coal-fired plants which use technology that reduces GHG emissions could be eligible under the EPS.

More importantly, the EPS does not discriminate based on geographic origin. In *City of Philadelphia*, the New Jersey statute prohibited the importation of "solid or liquid waste which originated outside the territorial limits of the State."[198] The Court explained: "whatever New Jersey's ultimate purpose, it may not be accomplished by discriminating against articles of commerce coming from outside the State unless there is some reason, *apart from their origin*, to treat them differently."[199] In sharp contrast, the geographic locality of a high-GHG emitter is irrelevant under the EPS.[200] An LSE is free to enter into long-term contracts

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[197] *See, e.g., CEED's Opening Brief on Jurisdictional and Other Legal Issues,* June 30, 2006, p. 7.

[198] *City of Philadelphia*, 437 U.S. at 618 (*Emphasis added*).

[199] *City of Philadelphia*, 437 U.S. at 627-28 (*Emphasis added*).

[200] In their Opening Brief of June 30, 2006 on p. 6 and their Reply Brief of July 11, 2006 on p. 4, CEED makes the claim that the "Order itself concedes, 'non-California

Footnote continued on next page

with both in-state and out-of-state generators because the EPS makes no distinctions between in-state and out-of-state sources of electricity. Indeed, the Attorney General comments that: "a substantial amount of electricity generated out-of-state would continue to be available for procurement" under the EPS.[201] For these reasons, we find CEED's argument to be without merit.

CEED additionally argues that the EPS discriminates against interstate commerce by treating California firms more favorably than out-of-state firms. CEED states that "the 60 percent capacity factor exempts the majority of California's in-state generators from the EPS."[202] This is a comparison between apples and oranges.

The EPS covers the California LSEs' long-term baseload procurement contracts. Most of the parties at the Commission's workshop on June 21-23, 2006, agreed that the EPS should apply to baseload generation plants that are intended to operate year-long at a high capacity factor, because these plants would provide the bulk of the LSEs' open procurement needs and the most significant amounts of GHG emissions. There was some disagreement as to whether the

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generators . . . must adjust their behavior' to comply with CPUC's GHG cap (and presumably with the interim EPS as well.)" The complete sentence on page 23 of D. 06-02-032, "The Opinion on Procurement Incentives Framework" (February 16, 2006), reads: "*California and* non-California generators are subject to the cap and must adjust their behavior accordingly." (*Emphasis added.*) Furthermore, the clear underlying implication of this sentence is that these firms should adjust their behavior only *if* they intend to enter into long-term contracts for the sale of electricity to California LSEs.

[201] *Reply Brief to CEED for the People of the State of California*, Oct. 31, 2006, p. 5 (citing *CO2 Emission from Coal and Natural Gas from WECC Power Plants with High Capacity Factor in 2005* (CEC, Oct. 27, 2006).). According to this CEC report, at least 22 major out-of-state plants would meet the EPS.

[202] *CEED's Comments on Draft Workshop Report,* September 8, 2006, p. 15.

capacity factor should be at least 50% or 60%. However, most parties agreed with the 60% capacity factor, because the utilities' data showed that a 60% (or greater) capacity factor would capture 78% of the utilities' 2012 open procurement needs and 72% of the associated CO_2 emissions.[203]

On the other hand, there was general agreement at the Commission's workshop that the EPS should not apply to generation plants that operate at a low capacity factor to meet peaking or other reliability needs. Parties agreed that the EPS should not apply to these types of generation plants because it could be detrimental to the reliability and performance of the transmission grid and it would not reduce a significant amount of additional CO_2 emissions.[204] While the California utilities procure electricity from some out-of-state low capacity plants, both the Commission and the California ISO have recognized that many low capacity local generators are required to generate electricity at specific locations for the operational reliability of the electric transmission grid.[205]

In view of the above, long-term baseload generation operating at a capacity factor of 60% or greater performs a totally different function and would be responsible for a much greater amount of GHG emissions than low capacity factor generation (such as peakers) operating at a capacity factor of less than 60%; including many which are operating only 10% or 20% of the time during

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[203] *See* Draft Workshop Report, August 21, 2006, pp. 21-23, and its Summary of Comments, responses to Workshop Question # 4, p. 47. Subsequently, the 60% capacity factor was codified by SB 1368 § 2. *See Public Utilities Code* § 8340(a).

[204] *See* Draft Workshop Report, August 21, 2006, pp. 21-23, and its Summary of Comments, responses to Workshop Question # 4, p. 47.

[205] *See* D.06-06-064, "Opinion on Local Resource Adequacy Requirements" (June 29, 2006).

the year and are essential for the reliability of the grid. Thus, the generators competing under the EPS for long-term high capacity factor baseload contracts are not similarly situated with low capacity factor generation plants. Consequently, there is no legitimate claim of discrimination under the Commerce Clause based upon the exemption of low capacity generators from the EPS.[206]

Furthermore, as a preliminary estimation of non-exempt generators, the CEC states that more in-state than out-of-state facilities would fail to meet the EPS, and that more imported than locally generated electricity may meet the EPS.[207] Regardless, any shift towards or away from out-of-state resources is speculative at this point, and could not possibly indicate discriminatory intent. We therefore reject CEED's argument as factually and legally invalid.

CEED further argues that the EPS (and the GHG cap to be implemented in Phase 2) "places heightened financial burdens on the construction of new coal-fueled power plants in neighboring states."[208] This is based on the practice of using pre-construction contracts to secure financing for power plant construction.[209] CEED further argues that the EPS therefore provides California firms with a "significant competitive advantage" in securing financing.[210]

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[206] *See General Motors Corp.* v. *Tracy* (1997) 519 U.S. 278, 297-310.

[207] *Reply Brief to CEED Comments for the People of the State of California*, Oct. 31, 2006, p. 5 (citing *CO2 Emission from Coal and Natural Gas from WECC Power Plants with High Capacity Factor in 2005* (CEC, Oct. 27, 2006).).

[208] *See, e.g., CEED's Comments on Draft Workshop Report,* September 8, 2006, p. 17.

[209] *See, e.g., CEED's Comments on Draft Workshop Report,* September 8, 2006, pp. 17-18.

[210] *See, e.g., CEED's Comments on Draft Workshop Report,* September 8, 2006, p. 18.

The dormant Commerce Clause does not require California to protect the pecuniary interests of out-of-state coal burners.[211] Moreover, CEED's argument does not show that California firms will have a significant competitive advantage. As stated above, both California firms and out-of-state firms are covered under the EPS. The Supreme Court has observed that the Commerce Clause "protects the interstate market, not particular interstate firms, from prohibitive or burdensome regulations."[212] We find CEED's argument without merit.

CEED further complains that there is currently no cost-effective technology that would allow coal burners to meet the EPS[213] and also argues that the EPS would somehow hinder advanced clean coal technology development.[214] As NRDC, TURN, UCS and WRA note, there are already two planned generation facilities that intend to implement CO_2 sequestration, from day one of the plants' operation.[215] Thus, clean coal technology is now under development. By setting a GHG emissions limit, the EPS would create an incentive to further the development of clean coal technology rather than hinder it. Conversely, allowing California to remain reliant on high GHG-emitting energy sources would serve as a disincentive for the advancement of environmentally sound

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211 *See Exxon Corp.* v. *Maryland* (1978) 437 U.S. 117, 127-28.

212 *Id.*

213 *See, e.g., CEED's Comments on Draft Workshop Report,* September 8, 2006, pp. 13-14.

214 *See, e.g., CEED's Comments on Draft Workshop Report,* September 8, 2006, pp. 12-13.

215 *Opening Comments/Legal Brief on Final Workshop Report of NRDC/TURN/UCS/WRA*, October 18, 2006, p. 22.

coal technology. Regardless, as stated above, California is not required to protect the interests of "particular interstate firms."[216] We reject CEED's argument.

CEED has failed to meet the burden of demonstrating discrimination. Therefore, we hold that the EPS is an evenhanded regulation that does not discriminate against interstate commerce.

8.2. *Pike* Balancing Test

When a state enactment is not facially discriminatory, the *Pike* balancing test is generally applied. In *Pike* v. *Bruce Church* (1970) 397 U.S. 137, the United States Supreme Court established this test that weighs the local benefits against the burdens on interstate commerce, in order to determine if a particular state regulation violates the dormant Commerce Clause. A regulation's burdens on interstate commerce must be "clearly excessive" in relation to the local benefits in order for a regulation to be struck down under *Pike*.[217]

8.2.1. Local Benefits

Despite the restrictions of the dormant Commerce Clause, a state retains general police powers to regulate legitimate local concerns notwithstanding potential impacts on interstate commerce.[218] In SB 1368, the Legislature has made specific legislative findings regarding the local benefits of the EPS.[219]

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[216] *Exxon Corp.* v. *Maryland*, 437 U.S. at 127-28.

[217] 397 U.S. at 142.

[218] *Maine* v. *Taylor,* 477 U.S. at 138.

[219] CEED previously argued that: "in the absence of specific findings regarding putative local benefits, the proposed EPS presumptively violates the Commerce Clause." (*CEED's Reply Brief on Jurisdictional and Other Legal Issues,* July 11, 2006, p. 3.) This point has become moot with the passage of SB 1368.

Section 1(a) of SB 1368 reads: "Global warming will have serious adverse consequences on the economy, health and environment of California."

Regarding economic benefits, the Legislature found: "[T]hat federal regulation of emissions of greenhouse gases is likely"[220] "over the next decade"[221] and that SB 1368 serves to "reduce potential exposure of California customers for future pollution-control costs."[222] SB 1368 also reduces "potential exposure of California consumers to future reliability problems in electricity supplies."[223] Thus, the EPS serves to protect ratepayers from the costs and risks of complying with future laws and regulations that will further limit the emission of GHG gases in the process of generating electricity. If Californians are reliant on high-GHG emitting sources, whether in-state or out-of-state, future regulations could have a devastating impact on the California economy. Non-compliant energy sources would be forced to refurbish their facilities to meet these new standards, and the costs could be shifted to consumers. Whether or not costs are shifted, plants would likely be unable to continue supplying as much power to California while they are refurbishing. Further, the EPS encourages a wider range of clean energy sources, which protects the reliability of the grid. It is a legitimate local purpose to protect California consumers from financial risk in an evolving regulatory scheme, and ensuring a continuous supply of electricity for California customers.

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[220] SB 1368 § 1 (f).

[221] SB 1368 § 1(e).

[222] SB 1368 § 1 (i).

[223] SB 1368 § 1(j).

Regarding the health and environment of California, we look to the legislative findings of a related bill AB 32, and the Final Climate Action Team Report to the Governor and the Legislature (Presented to the Legislature in March, 2006) (CATR).[224]

In AB 32, Chapter 2(a), the Legislature found that:

> "(a) Global warming poses a serious threat to the economic well-being, public health, natural resources, and the environment of California. The potential adverse impacts of global warming include the exacerbation of air quality problems, a reduction in the quality and supply of water to the state from the Sierra snowpack, a rise in sea levels resulting in displacement of thousands of coastal businesses and residences, damage to marine ecosystems and the natural environment, and an increase in the incidences of infectious diseases, asthma, and other human health-related problems."

GHG emissions contribute to climate change.[225] By increasing the number of extremely hot days, and the "frequency, duration, and intensity of conditions conducive to air pollution formation, oppressive heat, and wildfires," the public health of Californians could be dramatically affected.[226] Climate change is also likely to increase infectious disease vectors such as mosquitoes, ticks, fleas and rodents, which would effectuate the negative health consequences discussed in AB 32. Similarly, climate change can increase asthma triggers such as pollen, dust mites, and molds.[227] The decreases to the Sierra Nevada snowpack

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[224] The CATR was drafted as part of a multi-agency effort to address climate change and its effects on California.

[225] Final Climate Action Team Report to the Governor and the Legislature, March, 2006, pp. 19-24.

[226] *Id.* at 25-27.

[227] *Id.*

mentioned in AB 32 would have far-reaching effects on California's water supply.[228] The snowpack provides a natural water supply to Californians, including agricultural growers.[229] Loss of the snowpack would result in decreased runoff, which would reduce the availability of the already overstretched water supply.[230] Electric supply from hydroelectric power plants is also likely to diminish, while demand continues to rise.[231] The rise in sea level described in AB 32 could submerge many of California's beaches and estuaries.[232] The occurrences of extreme oceanic events are also expected to rise with sea levels.[233]

The Attorney General introduced into the record substantial materials that corroborate these findings, and the linkage between anthropogenic climate change and negative health and safety impacts on California.[234] For instance, Dr. Reinhard E. Flick states that "all beaches in California will be negatively affected" as the result of climate change.[235] Dr. Michael Hanemann notes that

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[228] *Id.* at 28-29.

[229] *Id.*

[230] *Id.* A state's right to protect its water supply is well-established. (*See, e.g., Proctor and Gamble* v. *City of Chicago* (7th Cir. 1975) 509 F.2d 69 (Upheld city ordinance forbidding the sale and use of detergents containing phosphates, which had a detrimental affect on water supply.).)

[231] Final Climate Action Team Report to the Governor and the Legislature, March, 2006, p. 36.

[232] *Id.* at 31.

[233] *Id.* at 33.

[234] *Phase 1, Pre-Workshop Comments of the People of the State of California,* June 12, 2006, Exs. A-L.

[235] *Phase 1, Pre-Workshop Comments of the People of the State of California,* June 12, 2006, Ex. (Exhibit) F, p. 2.

climate change would reduce California's water supply while increasing water demand.[236] We thus hold that the EPS has significant local benefits.

8.2.2. Burden on Interstate Commerce

As noted above, CEED argues that the EPS will burden interstate commerce by limiting the construction of new coal-fueled plants. CEED also makes the speculative claims that the EPS would decrease the price of electricity for some out-of-state generators, and that clean coal technology is not commercially feasible. We have already shown how these alleged "burdens" are nondiscriminatory. More generally, CEED argues that: "the reality of California's energy market dictates that the [EPS] will primarily preclude out-of-state suppliers from competing in California markets"[237] and that the EPS burdens the economies of other states more than California.[238] CEED further argues that through coal displacement various interstate geographic regions of the United States would be negatively impacted in the future.[239]

CEED presents a report by "Energy Ventures Analysis, Inc." (EVA)[240] which states that: "[b]aseload power imported from the Southwest would be far harder hit than generation from the Pacific Northwest. Both major importing

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[236] *Phase 1, Pre-Workshop Comments of the People of the State of California,* June 12, 2006, Ex. G, p. 13.

[237] *See, e.g., CEED's Comments on Draft Workshop Report,* September 8, 2006, p. 15.

[238] *CEED's Comments on Draft Workshop Report,* September 8, 2006, Ex. 1, pp. 12-13.

[239] *CEED's Comments on Draft Workshop Report,* September 8, 2006, Exs. 4, 5, 6.

[240] Energy Ventures Analysis, Inc. (EVA) is a Virginia-based consulting firm which states on its website that is has assisted with: "[c]oal turnaround management and/or liquidations, including assuming coal company CEO and administrative responsibility." (<http://www.evainc.com/coal.htm>.)

areas would be hit much harder than in-state California plants."[241] The report speculates that 8-52 % of the existing Pacific Northwest imports would not meet the EPS, and that 54-86 % of the existing Southwest power imports would not meet the EPS.[242] However, assuming arguendo these numbers were accurate, as much as 92% of the existing Pacific Northwest imports would meet the EPS, and as much as 46% of the existing Southwest power imports would meet the EPS. Moreover, generators may make changes to existing generation plants or construct new generation plants out-of-state in order to meet the EPS.

We find the EVA report unpersuasive. Indeed, reducing reliance on high-GHG emitting resources is a major goal of the EPS. Whether one geographic region is impacted more than another is not relevant to a dormant Commerce Clause analysis beyond the distinction between in-state and out-of-state.[243] As to the in-state/out-of-state distinction, the Attorney General has provided factual evidence that contradicts EVA's conjectures.[244]

CEED also attaches a study purporting to show various costs that will be incurred as coal is displaced by other fuels. However, the authors of the study cautioned that their analysis "is not intended to measure the impacts of any

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[241] *CEED's Comments on Draft Workshop Report,* September 8, 2006, Ex. 1, p. 12.

[242] *CEED's Comments on Draft Workshop Report,* September 8, 2006, Ex. 1, p. 13.

[243] *Intra*state divisions are also remarked upon. The EVA report states: "[s]ince the performance standard discriminates against coal, Southern California may be most affected by prohibiting new baseload coal contracts. On the other hand, Northern California purchases and consumes more hydroelectric power." (*CEED's Comments on Draft Workshop Report,* September 8, 2006, Ex. 1, p. 13.)

[244] *See Reply Brief to CEED* Comments *for the People of the State of California*, Oct. 31, 2006, p. 5 (citing *CO2 Emission from Coal and Natural Gas from WECC Power Plants with High Capacity Factor in 2005* (CEC, Oct. 27, 2006).).

specific policy that could result in decreased coal production or utilization."[245] Environmental externalities such as pollution and GHG emissions were not considered in the study.[246] In any event, the fact that the displacement of coal may have some economic effects, does not establish an impermissible burden on interstate commerce.[247]

Overall, the "practical effect" argument CEED raises is analogous to a failed argument in *Minnesota* v. *Clover Leaf Creamery* (1981) 449 U.S. 456. In *Clover Leaf Creamery*, the Court upheld a Minnesota statute that banned the retail sale of milk in plastic nonreturnable, nonrefillable containers, but allowed such sale in other types of nonreturnable, nonrefillable containers.[248] The opponents of the statute argued that the "plastic resin . . . used for making plastic nonreturnable milk jugs, is produced entirely by non-Minnesota firms, while pulpwood, used for making paperboard, is a major Minnesota product."[249] The Court responded: "[e]ven granting that the out-of-state plastics industry is burdened relatively

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[245] *The Center for Energy and Economic Development's Comments on Draft Workshop Report,* September 8, 2006, Ex. 5, p. 18.

[246] *The Center for Energy and Economic Development's Comments on Draft Workshop Report,* September 8, 2006, Ex. 5, pp. 18-19.

[247] This study does not purport to attack the effects of the EPS per se, but rather deals with a nationwide trend, which DRA aptly points out "will not happen overnight." (*DRA's Written Reply to the Supplemental Material CEED on Commerce Clause Issues*, Nov. 1, 2006, p. 11.) Aside from that, the failure to incorporate the impact of externalities severely limits its usefulness in a dormant Commerce Clause analysis. DRA points to research that assessed such externalities. (*Id.* at pp. 11-14.) We find no need to delve into the exact valuation of externalities versus other economic costs, as this is both premature and unnecessary for our purposes.

[248] 449 U.S. 456.

[249] *Clover Leaf Creamery*, 449 U.S. at 473.

more heavily than the Minnesota pulpwood industry, we find that this burden is not 'clearly excessive' in light of the substantial state interest in promoting conservation of energy and other natural resources."[250]

As in *Clover Leaf Creamery*, the burdens cited by CEED cannot be deemed "clearly excessive" in light of the substantial local benefits of the EPS. Citing an October 30, 2006 Data Request Response from PG&E, SDG&E, and SCE, DRA points out that: "[a]s a practical matter, it appears that the duration of many energy contracts is less than five years."[251] As stated above, coal-based and other high-GHG emitting power sources, can still sell into California under these contracts. Existing contracts are also not under the purview of the EPS. In any event, nothing in the EPS prohibits carbon-rich producers from transmitting electricity through the California grid to other states and nations. Thus, the speculative costs from the EPS cannot be deemed "clearly excessive" when weighed against the important local benefits of protecting ratepayers and the California environment.[252]

For all the reasons stated above, we find that all of the alleged burdens are incidental and not clearly excessive in relation to the legitimate local benefits.

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[250] *Id.*

[251] *The Division of Ratepayer Advocates' Written Reply to the Supplemental Material of CEED on Commerce Clause Issues*, Nov. 1, 2006, p. 7.

[252] *See Clover Leaf Creamery*, 449 U.S. 456; *Exxon Corp.* v. *Maryland,* 437 U.S. 117; *Cf. Huron Portland Cement Co.* v. *City of Detroit* (1960) 362 U.S. 440.

8.3. Extraterritorial Effect

Like facially discriminatory legislation, an "extraterritorial" regulation is generally considered to be invalid per se.[253] In this context, extraterritorial regulation means regulation that impacts commerce that occurs "wholly" outside the state.[254]

CEED argues that the EPS will have an impermissible extraterritorial effect on interstate commerce. More specifically, CEED argues that the EPS will have the effect "of regulating the GHG emissions of out-of-state generators selling into the California market, thus unlawfully controlling commercial conduct beyond the borders of California."[255] In support of this argument, CEED cites *Healy* v. *Beer Institute* (1989) 491 U.S. 324, 336, for the proposition that: "[t]he critical inquiry is whether the practical effect of the regulation is to control conduct beyond the boundaries of the State." However, the practical effect of the Connecticut law challenged in *Healy* was that brewers could not offer volume discounts in Massachusetts, New York and Rhode Island, where they were legal. If they did so, the volume discount would have become the ceiling price for all sales in Connecticut, which did not allow volume discounts.[256]

The EPS does not directly regulate commerce that occurs "wholly out-of-state." It only regulates the procurement practices and contracts of California LSEs buying for the California retail market. As the Ninth Circuit explained in

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[253] *See*, *e.g.*, *Brown-Forman Distillers Corp.* v. *New York State Liquor Authority* (1986) 476 U.S. 573, 579.

[254] *Edgar* v. *MITE Corp.* (1982) 457 U.S. 624, 642-43.

[255] *See, e.g., CEED's Comments on Draft Workshop Report,* September 8, 2006, p. 18.

[256] *Healy*, 491 U.S. at 339.

Gravquick A/S v. *Trimble Navigation International Ltd.* (9th Cir. 2003) 323 F.3d 1219, 224, cases finding extraterritorial regulation "deal with laws that regulate out-of-state parties directly, not through contract."[257] The Ninth Circuit held that when a state regulates contractual relationships in which at least one party is located within California it does not regulate commerce entirely outside of the State of California.[258]

The EPS only applies to the California LSEs' procurement of electricity under long-term contracts with in-state or out-of-state suppliers. It does not apply to or regulate the sales of electricity to utilities, or other entities, in other states. Its reach is therefore not extraterritorial.[259]

An out-of-state company can still decide whether to sell electricity to the California LSEs under the EPS (e.g., by utilizing powerplants that already comply with the EPS, by retrofitting existing, non-compliant or by building a new complying powerplant), or the out-of-state company can choose to sell electricity to utilities in states other than California. Simply because the sales to California LSEs under the EPS may affect the costs or profit of an out-of-state generation company (as well as generators in California) does not make the

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[257] *See Healy,* 491 U.S. at 343 (invalidating statute that prevented sale of alcohol at a price higher than that sold in neighboring states).

[258] *Gravquick A/S* v. *Trimble Navigation International Ltd.*, 323 F.3d at 224.

[259] *See Cotto Way Co.* v. *Williams* (8th Cir. 1995) 46 F.3d 790, 794 (Minnesota law banning sale of petroleum-based sweeping compounds in Minnesota was not extraterritorial, because the statute was indifferent to sales in other states).

regulation extraterritorial.[260] We thus reject CEED's argument regarding extraterritorial effect.

8.4. Conclusion

For the reasons discussed above, we conclude that the EPS does not: 1) discriminate against interstate commerce, 2) impose excessive burdens on interstate commerce in relation to local benefits, or 3) have an extraterritorial effect. In sum, the EPS is valid under the dormant Commerce Clause. As stated aptly by the Ninth Circuit Court:

> "The constitutional principles underlying the Commerce Clause cannot be read as requiring the State … to sit idly and wait until potentially irreversible environmental damage has occurred … before it acts to avoid such consequences."[261]

9. Consideration of Effects on Reliability and Overall Costs to Electric Customers

SB 1368 directs that we consider "the effects of the standard on system reliability and overall costs to electricity customers" in developing and implementing the EPS.[262] We have done so in several ways. First and foremost, by ensuring that new long-term commitments to baseload generation will only be with facilities that emit no more than the GHG emissions rate of a CCGT, we have designed an interim EPS that will protect electricity customers from reliability problems and high compliance costs in the future. As discussed in

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[260] *See National Electrical Manufacturers Association* v. *Sorrell* (2d Cir. 2001) 272 F.3d 104, 110-111.

[261] *Pacific Northwest Venison Producers* v. *Baker* (9th Cir. 1994) 20 F.3d 1008, 1017, (quoting *Maine* v. *Taylor,* 477 U.S. at 148).

[262] § 8341 (d)(6).

today's decision, we have ensured this outcome by designing the EPS as the Legislature intended, namely, as a minimum standard of GHG emissions performance for covered procurements similar to an appliance efficiency standard. As SB 1368 recognizes, the resulting reduction in GHG emissions will mitigate adverse impacts on "the economy, health and environment," thereby reducing overall costs to all Californians, including electricity customers.[263]

In addition, the EPS is designed to capture the largest percentage of impact on GHG emissions without compromising system reliability. This is accomplished by defining covered procurements as new long-term commitments to baseload generation, thereby excluding the types of procurements that the LSE is most likely to need for system reliability requirements, i.e., short-term power purchases, long-term contracts with load-following and peaking generation facilities, or new construction of non-baseload powerplants. This focuses compliance on the types of facilities and commitments over which the LSE has the most discretion and choice, thereby minimizing the costs of compliance to the LSE and its electricity customers. In particular, as discussed in this decision, the definition of covered procurements will not subject the millions of dollars in the LSE's already-built facilities to a standard that is being developed to prevent backsliding in LSE decisions made for future investments. In the event that unforeseen reliability concerns and associated costs arise during implementation of the EPS, we have also provided for Commission review of requests for reliability exemptions on a case-by-case basis. Finally, we note that no showing

[263] § 8341 1(a).

has been made in this proceeding that new, EPS-compliant procurements will not be available at reasonable costs to ratepayers.

In sum, today's adopted EPS fulfills both the letter and the spirit of SB 1368 by effectively "raising the bar" for the GHG emissions performance of new long-term commitments with baseload generation serving California as we transition to a statewide GHG emissions cap.

10. Comments on Proposed Decision

The Proposed Decision of Assigned Commissioner Michael R. Peevey and ALJ Meg Gottstein on this matter was mailed to the parties in accordance with Public Utilities Code Section 311 and Rule 14.2(a) of the Commission's Rules of Practice and Procedure. Opening comments were filed on _________________ by _____________ and reply comments were filed on _____________ by ________________.

11. Assignment of Proceeding

Michael R. Peevey is the assigned Commissioner and Meg Gottstein is the assigned ALJ in this phase of the proceeding.

Findings of Fact

1. As described in this decision, the Commission has consulted with the California ISO, CARB and CEC during the development of the interim EPS rules.

2. SB 1368 establishes a minimum performance requirement for any baseload generation facility that represents a new long-term financial commitment entered into by entities providing power to California ratepayers. This minimum performance requirement is a GHG emissions performance standard, or "EPS," which limits the powerplant emissions rate to no higher than the emissions rate of a CCGT baseload powerplant.

3. The EPS functions similar to an appliance efficiency standard by ensuring that an LSE does not enter into long-term financial commitments with baseload resources that do not meet a minimum standard of performance.

4. The EPS serves to address the serious adverse consequences of global warming on California's economy, health and environment.

5. The EPS is needed to prevent "backsliding" during California's transition to a statewide load-based GHG emissions cap, that is, to reduce California's exposure to (1) the costs of complying with future laws and regulations that will further limit the emission of GHG gases in the process of generating electricity, and (2) future reliability problems, such as those caused by taking plants out of service to retrofit them (or to retire them early) in order to comply with future laws and regulations limiting GHG emissions.

6. The EPS will help protect Californians from climate change-related phenomena such as: increased number of extremely hot days, air pollution formation, oppressive heat, wildfires, infectious disease vectors, asthma triggers, decreases to the Sierra Nevada snowpack and its derivative effects on California's water supply, diminished electric supply, sea level rise, and the increased occurrence of extreme oceanic events.

7. For the reasons discussed in this decision, current Commission oversight of utility resource planning or the use of a GHG adder in utility procurement does not establish sufficient safeguards against the risks associated with long-term procurement commitments to high-emitting fossil-fueled facilities.

8. SB 1368 directs that the Commission reevaluate and continue, modify or replace the EPS adopted by this decision ("interim EPS") when an enforceable load-based GHG emissions limit is established and in operation.

9. There is insufficient data to create and enforce an EPS by the statutory deadline of February 1, 2007 that covers all six of the GHGs.

10. CO_2 is the most pervasive of the GHGs, and the most widely reported and verified of the GHGs at this time.

11. SB 1368 addresses the issue of what entities shall be subject to the EPS by directing that the Commission develop an EPS for LSEs, and by specifically defining that term in the new law.

12. Under SB 1368, the requirement to comply with the EPS is triggered if there is a "long-term financial commitment" by an LSE to baseload generation. For LSE-owned baseload generation, a long-term financial commitment occurs whenever there is a "new ownership investment." For baseload generation procured under contract, there is a long-term financial commitment when the LSE enters into a new or renewed contract with a term of five or more years.

13. SB 1368 defines baseload generation as "electricity generation from a powerplant that is designed and intended to provide electricity at an annual plant capacity factor of at least 60 percent, and defines the terms "powerplant" and "plant capacity factor" for this purpose as follows:

> (a) "Powerplant" means a facility for the generation of electricity, and includes one or more generating units at the same location.
>
> (b) "Plant capacity factor" means the ratio of the electricity produced during a given time period, measured in kilowatthours to the electricity the unit could have produced if it had been operated at its rated capacity during that period, expressed in kilowatthours.

14. A 60% capacity factor captures an estimated 78% of incremental procurement needs in 2012 for PG&E, SDG&E and SCE combined and would capture 72% of CO_2 emissions, based on the data submitted in Phase 1.

15. GPI's recommendation that the EPS be applied to generation from facilities with an annual plant capacity factor of at least 50 percent directly contradicts the plain language of SB 1368.

16. SB 1368 grandfathers CCGT baseload powerplants currently in operation, or that have a CEC final permit decision to operate as of June 30, 2007, as "deemed to be in compliance" with the EPS.

17. Under the provisions of SB 1368, an LSE does not enter into the types of commitments with "retained generation" (i.e., existing baseload facilities owned by the LSE to serve its load) that would trigger the requirement to comply with the EPS, absent additional investment.

18. Constellation et al.'s interpretation of SB 1368 of § 8341(d)(1) to mean that the Legislature intended to subject utility-owned retained generation to the EPS, with or without a "new ownership investment," would contradict the language of §§ 8341(a), (b)(1), (b)(2) and § 8340(j), or render it meaningless.

19. It is doubtful that the "rate recovery contract" with retained generation and kinds of regulatory measures that Constellation et al. describe in their comments are "contracts" as that term is ordinarily understood. Even if they are, they are not the kind of contracts that the Legislature describes in § 8340(j).

20. It is not clear under the proposal made by Constellation et al. how one would determine whether any particular "rate recovery contract" is for a period of less or more than five years.

21. Contracts for the procurement of baseload generation and "contracts" for the recovery of costs associated with generation are two separate things, and we read the plain language of SB 1368 to only apply to the former.

22. In the legislative history of SB 1368, "long term contract" is consistently referred to in the context of the procurement contracts covered by the Commission's procurement planning process, which do not apply to utility-retained generation.

23. Nothing in the statutory language or legislative history reflects the intent of the Legislature to define a "contract" in the manner suggested by Constellation et al.

24. The definition of covered procurements proposed by Constellation et al. would subject the millions of dollars in the LSE's already-built facilities to a standard that is being developed to prevent backsliding in LSE decisions made for future investments, and to avoid the additional financial and reliability risks that such backsliding would create.

25. SCE's interpretation of "long term financial commitment" under SB 1368 is that the Legislature intended to limit that commitment to an investment in baseload generation that is *also* a new ownership interest. In effect, under SCE's interpretation, the EPS would never be triggered for new investments made by the LSE to its retained generation.

26. SCE's assertion that the absence of a comma in the phrase "new ownership investment" mandates their reading is incorrect based on the rules of grammar described in several sources of grammatical usage. According to those sources, a comma would only be necessary if one could substitute the phrase "ownership, new investment" for the phrase "new, ownership investment" without affecting the meaning, which is not the case for the phrase "new ownership investment." These authorities also establish that no comma is required for this phrase, since the first adjective ("new") modifies the idea

expressed by the combination of the second adjective and the noun ("ownership investment").

27. As discussed in this decision, SCE's reading of § 8341(b)(6) in support of its interpretation is contrary to the plain meaning of the statute, which explicitly prohibits LSE's from entering into long-term commitments that fail to comply with the EPS.

28. We conclude from the legislative history that the Legislature added "new" to preclude the broader interpretation that would include all utility retained generation and not, as SCE contends, to exclude new investments in utility retained generation.

29. SB 1368 does not specify what types of new investments made by an LSE in retained generation would trigger the EPS.

30. An EPS trigger that identifies alterations to an existing powerplant that would increase the expected level of GHG emissions from the facility over the long-term is consistent with the overall objectives of SB 1368.

31. This would not be accomplished by requiring that any replacement of equipment or addition of pollution control equipment triggers compliance with the EPS, since the plant and its operation may remain essentially unchanged. More importantly, this approach could reduce powerplant reliability as old parts are repaired rather than replaced.

32. Setting a dollar level threshold to trigger EPS compliance for new ownership investments, as some parties suggest in their comments, would be an arbitrary exercise.

33. Defining the EPS trigger to include LSE investments in retained generation intended to (1) extend the life of one or more units of an existing busload powerplant for five years or more, or (2) that result in a net increase in

the existing rated capacity of that powerplant, is a workable definition that is consistent with the objectives of SB 1368.

34. Defining the EPS trigger in this manner covers "repowering" as the term is generally used in the industry, which is the type of investment in retained generation that staff and most parties agree should be included under the definition of new ownership investments.

35. Based on the common definition of the verb "deem," a CCGT powerplant that is *deemed* compliant does not have to demonstrate actual compliance with the adopted EPS standard, but is instead treated *as if* it met the EPS standard and is excused from making an affirmative showing of compliance.

36. The staff proposal would essentially apply the same standard of review for deemed compliant CCGT plants as for all other existing plants.

37. There is no indication in SB 1368, or in its legislative history, that the Legislature intended that CCGT powerplants, or any of the individual CCGT units such powerplants contain at the time they are deemed compliant, should lose their deemed-compliant status solely due to contract renewal.

38. Reading § 8341(d)(1) to require that the same kind and scale of alterations, improvements, additions, or renovations that constitute "new ownership investment" would also trigger a requirement that deemed-compliant CCGT powerplants demonstrate actual compliance with the EPS, would render the § 8341(d)(1) deemed-compliant provision redundant as applied to utility-owned CCGT powerplants.

39. In order to give §§ 8340(j), 8341 and 8341(d)(1) their full effect with respect to utility-owned CCGTs in operation as of the date of implementation of the EPS (or that obtain a CEC permit as of June 30, 2007), it is reasonable to

interpret SB 1368 to mean that "new ownership investment" in retained generation does not automatically trigger EPS review for deemed-compliant CCGT powerplants.

40. Interpreting SB 1368 to mean that existing CCGT are deemed to be permanently in compliance regardless of any subsequent changes to the facilities, however, would lead to absurd results, e.g., it would allow an LSE or non-LSE owner to circumvent the EPS simply by co-locating additional units with existing units within a previously deemed-compliant CCGT powerplant.

41. The deemed-compliant status is given to existing CCGT plants, and extending the exemption to units that did not exist at the time of the passage of the statute is contrary to the purpose and the intent of the law.

42. To give meaning to each section of the statute and avoid absurd results, it is reasonable to require EPS compliance when units are added to a deemed-compliant CCGT powerplant that result in a significant increase to the powerplant's rated capacity.

43. Establishing a 50 MW threshold for this purpose recognizes that Public Resources Code § 25123 establishes a 50 MW threshold to demarcate the boundary between significant and minor changes in generating capacity for the purpose of triggering CEC powerplant permitting requirements.

44. Limiting our reading of what parts of a CCGT powerplant are deemed compliant (to exclude additional units totaling 50 MW or more) avoids redundancy and gives each word of § 8341(d)(1) a legal effect distinct from the other provisions of the statute.

45. Nothing in today's decision or SB 1368 limits the Commission's existing authority to require that utility-owned, or contracted for, CCGT powerplants are properly maintained and are operated as cleanly and efficiently as possible.

46. SB 1368 directs the Commission to establish an EPS at a rate of emissions of GHGs that is "no higher" than the emissions rate of a CCGT powerplant, but does not specify the emissions rate for a CCGT.

47. SDG&E/SoCalGas interpret SB 1368 to mean that the Legislature intended for all deemed-compliant CCGTs to be able to demonstrate that they would pass the adopted standard, if they were required to do so.

48. Our reading of SB 1368, in conjunction with the common definition of the verb "deem," indicates that the Legislature intended to allow the Commission to adopt a standard that some deemed-compliant CCGT powerplants might not be capable of meeting.

49. Had the Legislature intended for the EPS to reflect the GHG emissions rate associated with gas-fired units, not just CCGTs, it would have stated so explicitly.

50. In selecting CCGT technology as the basis for the EPS, we must assume that the Legislature recognized that this technology is considered to be the technology of choice for new baseload power generation fired by natural gas due to its efficiency advantages over other forms of gas-fired power generation.

51. SB 1368 specifically directs that the EPS emissions rate be reflective of a baseload CCGT, and not intermediate/shaping gas-fired units, as some parties suggest in their comments.

52. An EPS performance level of 1,000 lbs of CO_2 per MWh is somewhat above the weighted average of 2004-2005 data of emission rates associated with a broad range of CCGT powerplants of varying vintages, but lower than the emission rates associated with the oldest, most inefficient "deemed compliant" CCGT powerplants still in operation.

53. In Resolution E-3940, this Commission found that a 1.5% increase in the referent CCGT baseload powerplant heat rate for the RPS was an appropriate value to use to reflect the impact of dry cooling, which offers the benefit of lower water consumption. As discussed in that Resolution, a 1.5% adjustment in the heat rate to reflect the impact of dry cooling is supported by the rule-of-thumb adjustment recommended by General Electric for F-series turbines with dry cooling. Even with this assumption, the heat rate of the market price referent was found to be 6,375 Btu/kWh, corresponding to a CO_2 emissions rate of 765 lbs of CO_2 per MWh.

54. Based on the record in this proceeding, an EPS emissions rate of 1,000 lbs of CO_2 per MWh is consistent with the intent of the Legislature to base the EPS on CCGT emission rates, and also allows for a reasonable level of efficiency reduction associated with CCGT technologies that offer the benefit of lower water consumption.

55. At the same time, an EPS emissions rate of 1,000 lbs of CO_2 per MWh avoids establishing a standard that is representative of the most inefficient, older CCGT powerplants in operation, which is appropriate in light of the statute's grandfathering provisions. Those provisions reflect the Legislature's concern that some of the older, less efficient CCGT powerplants in operation would not be able to meet the standard.

56. It is the characteristics of the powerplant(s) underlying new long-term contractual commitments that create the potential financial risk to California consumers and exposure to future reliability problems that this Commission and the Legislature seek to reduce through the establishment of an EPS.

57. Accomplishing the goals of SB 1368 and this Commission's GHG reduction policies requires looking at the characteristics and emissions of the

powerplant(s) being contracted for, *not* just the characteristics of the contracted-for deliveries, as some parties propose.

58. Interpreting the "supplied under" language of §§ 8341(a),(b)(1) and (3) as permitting us to assess the applicability of the EPS based only on the energy made available under contract to the LSE, rather than on the operations of the underlying powerplant, would :

> (a) Render useless the language of §§ 8341(4) that states:
>
> "In determining whether a long-term financial commitment is for baseload generation, the commission ***shall consider the design of the powerplant and the intended use of the powerplant…"*** (Emphasis added.)
>
> (b) Ignore that "supplied under" in all instances where it appears in SB 1368 follows the term "baseload generation," which is defined under § 8340(a) in terms of "*electricity from a powerplant* that is designed and intended to provide electricity at an annualized plant capacity factor of at least 60%." (emphasis added), and similarly,
>
> (c) Ignore that the term "plant capacity factor" is also defined by § 8340(1) in reference to the underlying plant operations.

59. Customer generators that sell power to the LSE under long-term contract (i.e., contracts with a term of five years or greater) still represents a resource upon which the LSE relies, even if the amount of energy delivered to the grid is small.

60. Application of the EPS should avoid situations where the LSE makes separate arrangements for high GHG-emitting resources that also generate power for on-site load, since the same risks of high costs and reliability problems in the future apply to those facilities.

61. Applying the EPS to the characteristics of the underlying facility or facilities supplying power under contract to the LSE, irrespective of whether

those facilities are operated by a customer generator or by a merchant generator, ensures that LSEs do not enter into long-term contract commitments with powerplants designed and intended for baseload operations with GHG emissions higher than CCGT powerplants. As discussed in this decision, the treatment of the powerplants under EPUC/CAC's example is consistent with this purpose, and does not create a "possible discrimination" between customer-owned generation and merchant generation.

62. By law, the EPS governs the long-term financial commitments of LSEs to any baseload generation, and SB 1368 directs this Commission to design and implement an EPS for this purpose.

63. Once a customer generator decides to offer power over and above its own (or over the fence) on-site consumption to an LSE under a contract of five years or more, the power supplied comes under Commission purview for the purposes of evaluating the LSE's (not the customer generator's) compliance with the EPS.

64. Staff's proposed treatment of partial contracts would exempt partial year contracts from the EPS if the contracted-for hours of energy delivery under the contract represent less than 60% of the total number of hours in the year. In effect, this represents a blanket exemption for seasonal procurements, even if the underlying facility generating the summer product is a baseload generation facility as defined under SB 1368.

65. Considering the expected capacity factor of the contractual commitment (not the underlying powerplant(s)) for partial-year contracts is inconsistent with the application of the EPS to all other contract commitments under the adopted EPS, and would create a significant loophole in EPS compliance.

66. Staff's proposed treatment of partial contracts is not necessary to address potential seasonal reliability concerns. To the extent that such concerns arise

from the application of an EPS that applies only to long-term contractual commitments with baseload facilities, LSEs may request a reliability exemption on a case-by-case basis, as provided for by this decision. There is no compelling reason to create a blanket exemption for this purpose.

67. Staff's and GPI's proposal for firmed renewable products applies the EPS from the viewpoint of contract deliveries, i.e., by applying the EPS on a blended basis to the contracted-for deliveries from the renewable and non-renewable resources underlying that product. In general practice, this means that the procurement would be automatically exempt from the EPS as long as less than half of the deliveries are from the non-renewable firming resource.

68. PG&E's proposed treatment of firmed renewable products would exempt all firmed renewable product from the EPS, irrespective of the emissions profile of the underlying nonrenewable firming resource or the level of deliveries from that contract.

69. The proposed treatment of firmed renewable products presented by staff, GPI and PG&E is inconsistent with the direction of SB 1368 that EPS-compliance be based on the underlying facility or facilities producing power, not just the delivered product under a contract.

70. Nothing in the language of SB 1368 or its legislative history indicates that the Legislature intended to carve out an exception for firmed renewable products.

71. The proposal of NRDC, TURN, UCS, WRA and DRA to apply the EPS to each facility underlying a contract, including one for a firmed renewable product, is consistent with the plain language of SB 1368.

72. SB 1368 does not specifically address instances where different resources or technologies might be generating power at the same location, e.g., a renewable

resource located in the same generating station as a fossil-fueled unit. Interpreting SB 1368 to mean that the term "powerplant" treats each of these distinct and separate generating sources as a single facility would effectively permit the blending of high GHG-emitting resources with low- or zero-emitting resources simply due to the physical co-location of the generating facilities. This could lead to an absurd result where power stations are expanded in order to co-locate high emitting generator sources with renewable or low-emitting CCGTs, in order to circumvent the EPS rule.

73. PG&E's argument that SB 1368 permits a small facility or contract size exemption violates a basic rule of statutory construction by ignoring the "any" and "all" language of §§ 8341(a) and 8341(d)(1).

74. We cannot reconcile PG&E's recommendation for a small size exemption with the plain language of SB 1368.

75. The legislative history of SB 1368 provides no indication that the Legislature ever considered including a blanket exemption for facilities or commitments under a certain size.

76. Any selection of a size threshold for such an exemption would be an arbitrary one, and could have the unintended consequences of driving down the size of high-emitting facilities for the sole purpose of obtaining an exemption from the EPS.

77. A blanket exemption for small utilities (less than 75,000 retail customers) is not provided under § 8341(d)(9) as CEED suggests, but rather, that section of the statute states that the Commission may accept proposals for alternate compliance from multi-jurisdictional utilities under specific circumstances. Moreover, a blanket exemption for all utilities with less than 75, 000 customers

would not achieve the same level of emissions reductions and associated reduction in future risks and costs intended by the Legislature.

78. SB 1368 provides the flexibility to both encourage new technologies while meeting the EPS standard. In particular, SB 1368 directs the Commission to: (1) calculate emissions rates based on "net emissions" from the production of electricity and (2) not to count CO_2 that is injected in geological formations as emissions of the powerplant in determining compliance with the EPS. However, neither the plain language of SB 1368 nor the legislative history indicates that the Legislature contemplated the type of RD&D exemption proposed by staff when drafting the statute.

79. Calculating the emissions rate of powerplants with sequestration projects contemplated under § 8341(d)(5) based on the net emissions over the life of the powerplant recognizes that a CO_2 injection project may not be operational until after the powerplant comes on-line or the LSE enters into the contract.

80. Implementing §§ 8341(d)(2) and (5) to require EPS compliance based on reasonably projected net emissions over the life of the facility serves the purposes of SB 1368.

81. EPUC/CAC's recommendation that all existing gas-fired cogeneration should be deemed to be in compliance with the EPS is inconsistent with the plain language of SB 1368, including § 8341(d)(3) directions on how the emissions for cogeneration facilities should be calculated in demonstrating EPS compliance.

82. Both topping and bottoming cycle cogeneration generate electricity. Bottoming cycle cogeneration generates electricity using waste heat from an industrial process, whereas topping cycle cogeneration does the reverse: It utilizes the waste heat from the generation of electricity.

83. ECAC/CAC's assertion that bottoming-cycle cogeneration is not a powerplant does not comport with the SB 1368 definition of powerplant as a "facility for the generation of electricity."

84. SB 1368 does not distinguish between topping and bottoming cycle cogeneration in the application of the EPS.

85. EPUC/CAC provide no evidence for their assertion that there are no emissions associated with the production of electricity using bottoming cycle cogeneration technologies.

86. EPUC/CAC acknowledge, in fact, that when supplemental firing is used to enhance the performance of bottoming cycle facilities, any resulting emissions attributable to the supplemental firing may need to considered in developing an emissions rate for the cogeneration facility.

87. By limiting the application of the EPS to long-term commitments, rather than short term transactions, and to baseload powerplants, rather than to those designed to be used for load shaping or peaking, the adopted EPS protects California ratepayers from long-term reliability risks while minimizing potential adverse impacts on short-term reliability and associated costs.

88. Applying the interim EPS on a gateway basis also provides LSEs with the flexibility to operate their facilities differently than originally designed or intended in order to address unanticipated short-term reliability needs.

89. A reliability exemption will probably not be needed given the definition of covered procurements and other design aspects of the interim EPS. Nonetheless, allowing for the possibility of granting this limited exemption, on a case-by-case basis, addresses concerns that unexpected reliability problems may arise during EPS implementation.

90. A reliability exemption is workable to implement, since a specific reliability concern and associated costs may be readily assessed as the "go, no-go" decision is being made for each new long-term financial commitment with baseload generation.

91. In contrast, in the context of an EPS no single procurement can be said to cause significant cost or economic impacts, in and of itself, for a utility's customer. This is because by its very nature and purpose, and similar to an appliance efficiency standard, the EPS requires that each determination be made without respect to whatever set of energy procurement opportunities a given LSE has available.

92. No party proposing cost-based exemptions or cost containment measures provides any evidence that the costs to ratepayers of procuring EPS-compliant resources will be unreasonable, or considers the economic, health and environmental benefits associated with the EPS in arguing that such proposals are warranted.

93. Price caps in the context of an EPS could mean that a long-term commitment to an otherwise non-compliant plant should nevertheless get a "go" rather than a "no go" because the cost of reducing GHG emissions for that particular plant would exceed more than $s/ton. Or, as in the case of the Massachusetts, Oregon and Washington price cap policies mentioned by CEED, the long-term commitment should be allowed because the LSE can pay $x/ton to a qualifying organization (e.g., the Massachusetts GHG Expendable Trust) for each ton above the standard.

94. Either way, price caps would allow the LSE to build or enter into long-term contracts with high GHG-emitting plants without any reduction in those

plants' emissions. This would undermine the SB 1368 goal of protecting ratepayers from the risks of entering into long-term commitments to high GHG-emitting baseload facilities in the first place.

95. No party has addressed how such a price cap could realistically be established by the statutory deadline of February 1, 2007.

96. It is reasonable to make some provision in our rules for "extraordinary circumstances, catastrophic events, or threat of significant financial harm" that may arise during EPS implementation due to unforeseen circumstances.

97. SB 1368 requires the Commission to adopt a methodology for calculating the emissions rate associated with cogeneration facilities that recognizes both the thermal and electrical output associated with cogeneration.

98. The Heat Rate of the Generator Method for calculating the emissions rate of cogeneration does not recognize that the thermal output (from the primary electric generation process) at a cogeneration facility will most likely be used directly as steam to do work, not converted into electricity in a secondary electric generation process that would incur the thermodynamic losses at the heat rate of the generator.

99. Using an electric heat rate to convert thermal energy output to kWh in this manner can double count the efficiency losses in the context of an output-based methodology.

100. The Avoided Emissions Method is problematic because it can be very difficult to determine the characteristics of the stand-alone boiler whose GHG emissions are avoided by a cogenerator. As a result, future power contract negotiations could end up being extremely complex and contentious over this issue.

101. The record in this proceeding does not provide us with a reasonable approach for estimating the emissions from the boiler that would be utilized in the absence of cogeneration. SDG&E/SoCalGas' assumption of 80% efficiency for such a boiler is an arbitrary selection.

102. The CEC data that SDG&E/SoCalGas suggest could instead be used to determine the general efficiency of gas boilers may not be representative of boilers located outside of California and, in any event, it would be inaccurate to assume that general efficiency for all boilers since not all cogeneration facilities are gas-fired.

103. Cogeneration facilities under consideration are not necessarily new facilities. Therefore, it would be inaccurate to assume that the boiler used in its place would have efficiencies that meet current standards, as SDG&E/SoCalGas suggest as an alternative.

104. A comparison of the Avoided Emissions Method with the Conversion Method also reveals that the Avoided Emissions Method may effectively ignore important fuel savings benefits associated with cogeneration. This appears to be due, in large part, to the fact that the Avoided Emissions Method uses two different resources to produce two different products (electricity and steam), whereas cogeneration uses one process that captures the benefit of two products. As a result, the Avoided Emissions Method may calculate an emissions rate based on the use of more fuel than a cogeneration facility might otherwise use during its actual operation.

105. In contrast to the Heat Rate of the Generator Method, the Conversion Method represents an output-based method that appropriately recognizes that the thermal output of a cogeneration facility can be used directly as steam to do work, and not for the secondary production of electricity.

106. Relative to the Avoided Emissions Method, the Conversion Method has the advantage of being (1) more accurate in calculating the actual emissions rate of the cogeneration facility, since it takes into account the actual thermal output of the cogeneration facility, (2) easier to implement and administer because it does not involve making assumptions about the type of boiler "avoided" and associated emissions rates. In addition, the Conversion Method fully recognizes the fuel savings benefits associated with cogeneration.

107. The emissions and cogeneration credit calculations presented in Attachment 5 are currently shown as though the facility operates as a topping-cycle facility. These calculations can readily be shown for a bottom-cycle facility by: (1) showing the thermal output first, following by the electric output in Tables A, B and C and (2) rearranging Table D so that thermal output precedes electric output.

108. The FERC definition of "useful thermal energy" in its regulations mandating the minimum efficiencies of a QF recognizes that there are losses from converting available thermal energy into "useful work," and that some of the available thermal output may be wasted (not "used") by the thermal host.

109. Using the existing documentation requirements of cogeneration facilities, as described in this decision, represents a reasonable and workable way to document the useful thermal energy output and other values for the Conversion Method formula of cogeneration facilities at EPS gateway screen.

110. Based on our reading of SB 1368, we are not precluded from making an upfront one-time determination of EPS compliance for renewables based on our consideration of representative emission rates.

111. It would be redundant and costly to require that LSEs demonstrate EPS compliance for each new ownership investment, new contract or renewed

contract with baseload renewable resources if the record clearly demonstrates that these resources comply with the EPS on a net emissions basis.

112. The record in Phase 1 demonstrates that the net GHG emissions produced from the renewable resources and technologies listed below are either zero, significantly less than the EPS or even result in a net reduction in GHG emissions (in the case of biomass):

(a) Solar Thermal Electric

(b) Wind

(c) Geothermal, with or without reinjection

(d) Generating facilities (e.g., agricultural and wood waste, landfill gas) using biomass that would otherwise be disposed of utilizing open burning, forest accumulation, landfill (uncontrolled, gas collection with flare, gas collection with engine), spreading or composting.

113. The usual disposal options for biomass wastes emit large quantities of methane gas, which is some twenty-five times more potent as a GHG than CO_2.

114. Electric production alternatives either burn the wastes that would become methane gas or burn the methane gas itself, generating CO_2.

115. Electricity production using biomass that would otherwise be disposed of under a variety of conventional methods (such as open burning, forest accumulation, landfills, composting) results in a substantial net reduction in GHG emissions.

116. It would not be reasonable for us to make a blanket determination today that *all* renewable resources or technologies are EPS-compliant, however, since the evaluation of net emissions presented on the record and discussed in parties' comments did not consider any other types of renewable resources or technologies (e.g., hydroelectric, fuel cells, photovoltaics, biodiesel, and ocean

thermal systems), or biomass generating projects where growing the fuel is required.

117. The issue of how to treat RECs or "null renewable power" (renewable resources that have sold off their RECs) in the context of EPS compliance should be addressed even though there is no tradable regulatory REC market in California at this time. Deferring the issue would introduce considerable uncertainty with respect to the treatment of renewables and create a potentially dampening effect on the development of these resources.

118. In the context of an RPS program, the REC that is sold carries with it all the renewable attributes associated with the production of electricity so that another entity (LSE) can apply those attributes to meet its RPS obligation, which is also defined in terms of electricity production.

119. In the context of EPS compliance, however, stripping renewables of their emission profiles when RECs are sold could easily create a "perverse" result, namely, it could discourage new long-term commitments with baseload renewable generators that have zero, low or even negative net GHG emission profiles in favor of facilities with higher GHG emission profiles.

120. As long as RECs cannot be used to offset emissions for the "go, no-go" EPS-compliance determination, looking at the actual nature of the underlying plant even if RECs are sold does not create a double counting problem. Moreover, such treatment is not inconsistent with § 399.12, as amended by SB 107, which provides that a REC "includes all renewable and environmental attributes associated with the *production* of electricity" (emphasis added), not discrete investment decisions.

121. As discussed in this decision, stripping renewables of their emissions attributes in the context of EPS compliance could result in the emissions from

two identical renewable baseload generators that sell off their RECs being valued very differently, depending upon who owns the generator.

122. Stripping renewables of their emissions attributes with the sale of RECs requires imputing emission factors to the resulting null renewable power, for which we lack a reasonable method at this time.

123. SB 1368 directs this Commission to address long-term purchases of electricity from unspecified sources (or "unspecified contracts") in a manner consistent with the statute.

124. To be consistent with SB 1368, unspecified contracts should be addressed in a manner to ensure that:

(1) LSEs only enter into long-term financial commitments with baseload generation that comply with the EPS, and

(2) EPS compliance cannot be achieved in a manner that would yield a contrary result, i.e., that permits an LSE to enter into long-term commitments with high-emitting sources.

125. The concept of imputing emissions rates with the requirements of SB 1368 is difficult to reconcile with the requirements of SB 1368 since, by definition, such proxies do not reflect the actual emissions from a resource. As a result, using imputed emissions rates does not permit one to determine whether a commitment with an unspecified resource is consistent with SB 1368 or simply exacerbates the problems this Commission and the Legislature are trying to address.

126. Any method to impute a GHG emissions rate to unspecified resources results in a binary outcome in the context of an EPS—that is, all financial commitments with unspecified resources will either "pass" or "fail" based on the selected level of imputed emissions. This results in enormous pressure to game the methodology and input assumptions used for this purpose, thereby making

it very difficult and contentious to implement this particular approach to addressing unspecified contracts.

127. As illustrated in comments in this proceeding, various input assumptions associated with calculating an imputed emissions value using the California Net Power Mix, as well as other proxies for the resource mix, can be manipulated to "push" an unspecified contract through the EPS.

128. SCE's recommendation for the treatment of unspecified contracts also has the potential to push an unspecified contract through the EPS gateway, since the proposed default rates are based on broad regional averages that would permit high emitting resources to pass through the EPS screen.

129. Under SCE's proposal, the case-by-case review would be one-sided: The Commission would be asked to grant an exception to the imputed emissions value only in those instances where the power is being purchased from a group of very low emitting resources (e.g., a group of all hydroelectric power plants), but not when the opposite may be true.

130. The WECC system average is generally not reflective of California activities or markets.

131. The use of WECC sub-regional geographic averages, including SCE's proposed alternative of using the WECC California region average carbon intensity factor, represent broad emissions averages that would dilute the impact of high-emitting resources and potentially allow them all to automatically pass through the EPS screen.

132. The California Net Power Mix is a calculation based on what is left over after the amounts that retailers voluntarily report as the resources underlying their short- and long-term power purchases (and accounting for on-site generation). It was developed by the CEC for power content labeling, and has

not been revised, updated or endorsed by the CEC for use in inputting GHG emissions under SB 1368 or in any other GHG policy context.

133. There is no clear conceptual link between the California Net Power Mix and the mix of resources that might underlie unspecified contracts now or in the future, even on a system-wide basis.

134. Requiring all long-term commitments for baseload generation be made with "specified resources" that can demonstrate compliance with the interim EPS is fully consistent with SB 1368. This approach ensures that "any" and "all" long-term financial commitments with baseload generation will meet the EPS, as the statute so directs.

135. SCE, SDG&E and PG&E did not enter into any contracts of five years or more for unspecified resources in 2004 and 2005 and state that they do not anticipate entering into any contracts with unspecified resources with a term of five years or more during the 2006-2008 procurement period.

136. Based on the record in this proceeding, it appears highly unlikely that LSEs will be entering into any new or renewal power purchase contracts of five years or greater that are unspecified during the transition to a statewide GHG emissions limit.

137. Requiring all long-term contracts with baseload generation be "specified" in order to demonstrate EPS compliance should not have a significant, if any, impact on an LSE's resource procurement flexibility.

138. The ISO relies on specific information about the plant facility and its location in making system reliability determinations within the ISO control area; therefore, the requirement to specify the resources underlying long-term contracts for the purpose of demonstrating EPS compliance is consistent with the type of information that the ISO also requires for these reliability determinations.

139. A requirement that long-term power purchase contracts specify the underlying generation facilities for EPS compliance is consistent with our discussion of emissions registration in D.06-02-032 and represents a logical interim step towards the implementation of the statewide emissions cap under AB 32.

140. Permitting LSEs to enter into new or renewed long-term unspecified contracts with high GHG-emitting facilities through the use of an imputed emissions value for system power could put them, and their customers, in a vulnerable position when the AB 32 reporting requirements take effect in 2008 for the implementation of the statewide, load-based GHG emissions limits.

141. The record indicates that it is entirely feasible to implement a program that tracks the GHG emissions of all generating units, and that would enable marketers and other sellers of unspecified resource contracts to assign a reasonable and accurate GHG emissions profile to their contracts. As discussed in this decision, specific tagging mechanisms have been developed in other jurisdictions to track generation attributes, including GHG emissions, and a similar information system is under development by the CEC for California to track compliance with RPS requirements.

142. A gateway screen approach for demonstrating compliance with the interim EPS is consistent with the intent of SB 1368, which directs us to look to the "design and the intended use" of the powerplant under § 8340(a).

143. A gateway screen approach is the most practicable and enforceable manner in which to determine EPS compliance.

144. As discussed in this decision, EPS compliance submittals can be readily incorporated into existing Commission procedures for LSEs that currently file

their procurement plans and contracts for Commission pre-approval, namely for SCE, PG&E and SDG&E.

145. New procedural vehicles need to be established for LSEs that are not currently required to submit procurement plans or apply for Commission pre-approval of procurement contracts, that is, for community choice aggregators, electric service providers and the small electrical corporations" (those other than PG&E, SCE and SDG&E).

146. Permitting small electrical corporations, electric service providers and community choice aggregators to submit an after-the-fact EPS compliance showing avoids creating new pre-approval requirements and associated administrative complexity for the Commission's regulation of the procurement practices of these entities.

147. Permitting small electrical corporations, electric service providers and community choice aggregators to file an after-the-fact compliance submittal for EPS compliance is consistent with other procurement-related compliance procedures we have established for electric service providers and community choice aggregators.

148. The documentation and other requirements adopted in this decision provide reasonable safeguards against the risks to ratepayers of potential non-compliance by an LSE that files an after-the-fact compliance showing.

149. For the reasons discussed in this decision, the resource adequacy filing submitted by these entities is not the appropriate procedural vehicle for documenting after-the-fact EPS compliance.

150. An annual Attestation Letter, filed as an advice letter with opportunity for response/protest, is a reasonable procedural vehicle for community choice

aggregators, electric service providers and small electrical corporations to use for documenting after-the-fact compliance with the interim EPS standard.

151. As discussed in this decision, an electric service provider, community choice aggregator or small electrical corporation should also be permitted to file an Advice Letter requesting Commission pre-approval of a new financial commitment as EPS compliant.

152. Under SB 1368, the Commission may consider a showing of "alternate compliance" by multi-jurisdictional electrical corporations that serve 75,000 or fewer retail end-use customers in California pursuant to § 8341(d)(9).

153. The two multi-jurisdictional utilities subject to SB 1368, Sierra Pacific and PacifiCorp intend to seek Commission approval of alternative compliance with the EPS.

154. Providing guidance as to how these utilities can demonstrate alternative compliance would facilitate their preparation of resource plans that they will be presenting to several public utilities commissions.

155. There is no compelling reason to defer our decision to provide such guidance, as some parties recommend.

156. PacifiCorp's three alternative compliance tests closely track the statutory language and appear consistent with staff's final recommendations.

157. The EPS serves a fundamentally different purpose, reflecting different policy objectives, than programs to reduce GHG emissions through a portfolio-wide cap, cap-and-trade programs or programs that permit LSEs to create or purchase offsets to meet an emissions cap or performance standard. As discussed in this decision, the purpose of these programs is to provide varying degrees of compliance flexibility when the primary policy goal is to reduce the overall level of emissions generated through procurement activities.

158. The purpose and objective of the interim EPS (i.e., to ensure that the LSE does not enter into- long-term financial commitments with high-emitting baseload resources in the first place) cannot be accomplished if LSEs are permitted to comply with the standard by diluting the emissions from high-emitting powerplants through portfolio averaging, or by increasing the permissible level of emissions for non-compliant powerplants through offsets or other means.

159. Portfolio averaging or increasing the permissible level of emissions for non-compliant powerplants through offsets or other means would only disguise the types of problems that the EPS is designed to avoid, e.g., the high costs of future plant retrofits and reliability disruptions as it becomes increasingly difficult for these high-emitting facilities to comply with GHG emission regulations.

160. A workable offsets program cannot be designed and implemented within the timeframe contemplated for an interim EPS, particularly in light of the SB 1368 statutory requirement that an enforceable EPS be put in place no later than February 1, 2007.

161. The documentation required by this decision will provide this Commission and Commission staff with information necessary to review EPS compliance, either in pre-approval requests or in reviewing after-the-fact Attestation Letters.

162. Disclosure of short-term contracts is necessary to ensure that LSEs do not circumvent the EPS rule by entering into a series of contracts with terms of less than five years with the same supplier, resource or facility. Such multiple contracts should be considered a single commitment and must be reviewed as

such (e.g., a contract for a three-year term linked to a contract for the following three years must be seen as a single commitment for 6 years).

163. Disclosure of LSE investments in retained generation, including "deemed-compliant" CCGTs is necessary to monitor compliance with the adopted EPS rules.

164. Consistent with the guidance in § 8341(b)(4), LSEs should present documentation that relates to establishing the design and intended use of the powerplant.

165. The full load heat rate is the heat rate of a plant at full output and is not representative of the actual operations of a plant.

166. LSEs should provide documentation of capacity factors, heat rates and corresponding emission rates that reflect the actual, expected operations of the plant.

167. Defining the term "annualized" in § 8340(a) to mean "annual average" is reasonable based on the common definition of the word "annualize," namely "to calculate or adjust to reflect a rate based on a full year."

168. To be applied in a manner that is consistent with this decision, the annual average capacity factor must be calculated based on the annual production of the underlying facility, and not just what might be delivered under a specific contract with an LSE.

169. A plant's operations may vary significantly from year to year, based on weather, maintenance schedules or economic conditions.

170. There are likely to be situations where more than a single year of annual electricity production will need to be considered in determining whether or not a powerplant is a baseload facility as defined under § 8340(a), i.e., whether it is

"designed and intended" to provide electricity at an annualized plant capacity factor of at least 60 percent.

171. The definition of "plant capacity factor" under § 83401(l) provides for consideration of more than a single year, in that it expresses the capacity factor as a ratio of electricity produced to electricity production at rated capacity "during a given time period."

172. SCE, PG&E and SDG&E are in the process of preparing and submitting long-term procurement plans for Commission pre-approval in R.06-02-013, and may need to update those plans to reflect how they will comply with today's decision.

173. Developing or clarifying the Commission's overall policies with respect to zero or low-carbon generation resources is beyond the scope of Phase 1.

174. The long-term procurement rulemaking, R.06-02-013 or its successor proceeding, is the appropriate procedural forum for the Commission's consideration of any requests by electrical corporations for § 8341(b)(6) rate-of-return increases on investments made by third parties.

175. Calpine's recommendation that the Commission take additional steps to encourage long-term commitments with resources with emissions below the EPS limit, including providing financial incentives, is beyond the scope of Phase 1.

176. It would be premature, and beyond the scope of Phase 1, to establish target dates in today's decision for the determination of emission allowances under a load-based cap, as recommended by San Francisco Community Power in their comments.

177. An LSE is free to enter into long-term contracts with both in-state and out-of-state generators because the EPS makes no distinction between in-state and out-of-state sources of electricity.

178. Under the EPS, electricity generated from high-GHG emitters can still be sold to California, under contracts of less than five years.

179. One limitation of the EPS is that until coal-fired baseload plants can meet the EPS, they cannot sign new or renewal contracts with a term of five years or more to supply California.

180. Coal-fired baseload facilities that use technology to reduce GHG emissions could meet the EPS.

181. Under the EPS, a substantial amount of electricity generated out-of-state would continue to be available for procurement.

182. Nothing in the EPS prohibits carbon-rich producers from transmitting electricity through the California grid to other states and nations.

183. Many low capacity local generators are required to generate electricity at specific locations for the operational reliability of the electric transmission grid.

184. Baseload generation operating at a capacity factor of 60% or greater performs a totally different function and would be responsible for a much greater amount of greenhouse gas emissions than low capacity factor generation (such as peakers) operating at a capacity factor of less than 60%, including many which are operating at only 10% or 20% of the time during the year and essential for the reliability of the grid.

185. The generators competing under the EPS for long-term, high-capacity baseload contracts are not similarly situated with low-capacity generation plants.

186. Any shift towards or away from out-of-state resources is speculative at this point, and could not possibly indicate discriminatory intent.

187. The EPS does not give California firms any competitive advantage over out-of-state firms.

188. By setting a GHG emissions limit, the EPS would create an incentive to further the development of clean coal technology, rather than hinder it.

189. The EPS does not apply to or regulate the sales of electricity to utilities, or other entities, in other states.

190. In developing the interim EPS, the Commission has considered the effects on reliability and overall costs to electric customers in the following ways:

a. By designing the EPS so that it functions similar to an appliance efficiency standard and thereby:
   i. Protecting electricity customers from reliability problems and high compliance costs in the future, and
   ii. Reducing GHG emissions that will mitigate adverse impacts on the economy, health and environment, which reduces overall costs to all Californians, including electricity customers.
b. By defining covered procurements as new long-term commitments to baseload generation, which:
   i. Captures the largest percentage of impact on GHG emissions,
   ii. Excludes the types of procurements that the LSE is most likely to need for system reliability requirements (e.g., short-term power purchases, long-term contracts with load-following and peaking generation facilities, or new construction of non-baseload powerplants), and
   iii. Focuses compliance on the types of facilities over which the LSE has the most discretion and choice, thereby minimizing the costs of compliance to the LSE and its electricity customers.
c. By not subjecting the millions of dollars in the LSE's already-built facilities to a standard that is being developed to prevent backsliding in LSE decisions made for future investments.
d. By providing for Commission review of reliability exemptions on a case-by-case basis in the event that unforeseen reliability concerns and associated costs arise during implementation of the EPS.

191. No showing has been made in this proceeding that new, EPS-compliant procurements will not be available at reasonable costs to ratepayers.

Conclusions of Law

1. For the reasons discussed in this decision, it is reasonable to limit today's adopted EPS to CO_2 emissions, at least at this time.

2. Pursuant to SB 1368, the EPS adopted today should apply to every electrical corporation, electric service provider or community choice aggregator serving end-use customers in the state, as the statute defines those terms.

3. The interim EPS should apply to baseload generation as that term is defined in SB 1368.

4. Constellation's proposal for defining covered procurements is not reasonable in light of the plain language of SB 1368, legislative history and the objectives of this Commission and the Legislature for an interim EPS, and should be rejected.

5. The interim EPS should define "long-term financial commitment" as set forth in § 8340(g) of SB 1368.

6. SCE's interpretation of "new ownership investment" to only encompass an investment in baseload generation that is *also* a new ownership interest is not reasonable for the reasons discussed in this decision, and should be rejected.

7. We conclude from our reading of SB 1368 that the term "new ownership investment" under SB 1368 encompasses new LSE investments in retained baseload generation.

8. As discussed in this decision, excluding retained generation from EPS-covered procurements (unless a review is triggered by a new "long-term financial commitment" as defined under SB 1368) is fully consistent with the

principles and objectives for an interim EPS articulated by the Legislature and this Commission.

9. For the reasons discussed in this decision, we conclude that it is reasonable and consistent with the direction of SB 1368 to apply the EPS to the following "covered procurements":

(1) New ownership investments in baseload generation made by an LSE, defined as:

  (a) Investments in new baseload powerplant (new construction), or

  (b) Acquisition of new or additional ownership interest in existing baseload powerplant previously owned by others, or

  (c) New investments in the LSE's own existing, non-CCGT baseload powerplants that are:

    (i) intended to extend the life of one or more units by five years or more,

    (ii) result in a net increase in the rated capacity of the powerplant, or

    (iii) intended to convert a non-baseload plant to a baseload plant, or

  (d) Units added to a deemed-compliant CCGT powerplant that result in an increase of 50 MW or more to the powerplant's rated capacity (the LSE owner need only show that the added units meet the EPS), or

(2) New contract commitments (including renewal contracts) of five years or greater by an LSE with:

  (a) baseload generation facilities, unless those facilities represent deemed-compliant CCGT powerplants, or

  (b) any deemed-compliant CCGT powerplant that added units resulting in an increase of 50 MW or more to the powerplant's rated capacity. (The contracting LSE need only show that the added units meet the EPS.)

10. The Commission retains the right to address questions related to the maintenance and efficiency of CCGT powerplants including but not limited to, the emissions from these plants, in the investor-owned utility general rate cases, long-term procurement plans, or other appropriate proceedings.

11. SDG&E/SoCalGas' suggestion that we establish the EPS level high enough to ensure that all deemed-compliant CCGTs could meet the standard is inconsistent with the Legislature's direction to deem them to be in compliance, based on the common definition of the term "deem," and should be rejected.

12. EPUC/CAC's suggestion that we establish an EPS level high enough to ensure that all gas-fired units meet it is inconsistent with the direction of SB 1368, and should be rejected.

13. Based on the record in this proceeding and direction of SB 1368, an EPS performance level of 1,000 lbs. of CO2 per MWh is reasonable and should be adopted.

14. Determining whether the EPS applies to a contract commitment should be made based on a "facility" basis, i.e., based on the characteristics of each generating source underlying the contract, and not on the contracted-for deliveries. This application of the EPS will further the policy objectives of SB 1368 and is supported by the rules of statutory construction.

15. Applying the EPS to the underlying facility in the case of customer generators does not exceed the Commission's jurisdiction or violate any laws, as some parties contend in this proceeding.

16. As discussed in this decision, a blanket exemption from the requirement to examine the capacity factor of the underlying facility for partial contracts is both unnecessary and inconsistent with other aspects of the EPS we adopt today.

17. For the reasons discussed in this decision, generating units utilizing different resources or technologies, no matter if they are at the same location or contracted for under the same purchase power agreement, must each be evaluated separately for the purpose of evaluating whether the resource operates as baseload generation and, if so, whether its emissions rate complies with the EPS.

18. For the reasons discussed in this decision, a small facility, commitment or service territory size exemption from the requirement to comply with the EPS should not be adopted, except as specifically provided for under § 8341(d)(9) for multi-jurisdictional electrical corporations that meet the alternative compliance requirements of that section.

19. Under federal law, California electric utilities are required to purchase energy from QFs.

20. Nothing in the language of PURPA or FERC's regulations requires utilities to offer QFs long-term contracts (contracts of five years or more).

21. Under SB 1368, electric utilities will still be required to purchase energy from QFs in compliance with PURPA. For those QFs that do not meet the EPS, utilities can meet the purchase obligation through contracts of less than five years.

22. Neither SB 1368 nor the Commission's implementation of it conflict with PURPA.

23. SB 1368 does not allow this Commission to provide exemptions for QFs unless application of the EPS would conflict with PURPA.

24. QFs should not be exempt from compliance with SB 1368.

25. It is reasonable and consistent with the language of SB 1368 to require EPS compliance of all covered procurements with gas-fired cogeneration facilities, including existing facilities and bottoming-cycle technologies.

26. Subject to the caveats discussed in this decision, it is reasonable to permit requests for reliability exemptions on a case-by-case basis, including reliability exemptions from the requirement that all covered procurements must be with specified resources.

27. Any consideration of reliability exemptions or requests to be excused from the requirements of this decision due to "extraordinary circumstances, catastrophic events or threat of significant financial harm" comes with a heavy burden of proof on the LSE. Any such requests should be pre-approved by this Commission.

28. Pursuant to § 8341(d)(6), the Commission has consulted with the California ISO during the development of the interim EPS rules and should continue to consult with the ISO during implementation in considering the effects of requests for reliability exemptions on system reliability and overall costs to electricity customers.

29. Approaches that would require us to assess costs or economic impacts on a case-by-case procurement basis are neither reasonable nor workable in the context of complying with the provisions of SB 1368.

30. LSEs should not petition to be excused from the requirements of this decision unless they can clearly demonstrate that: (1) they are facing extraordinary circumstances, catastrophic events or threat of significant financial harm not contemplated by SB 1368 and this decision, and (2) an exemption from some requirement of this decision is necessary to significantly mitigate or eliminate the challenges posed by these circumstances.

31. It is reasonable to adopt the Conversion Method of calculating cogeneration emission rates for the purpose of determining compliance with the interim EPS, with the clarification that the Btu Thermal Energy Output (expressed in kWh) in the formula represents "useful thermal energy" as defined in the FERC regulations implementing QF policy under PURPA.

32. Today's adopted approach for calculating and documenting cogeneration emissions rates for the interim EPS should not prejudge or predetermine the approach to be established in the context of the Commission's Procurement Incentive Framework or under the statewide GHG emissions limit envisioned under AB 32.

33. Based on the record in this proceeding, it is reasonable to make an upfront determination that the following renewable resources and technologies are EPS-compliant:

(a) Solar Thermal Electric

(b) Wind

(c) Geothermal, with or without reinjection

(d) Generating facilities (e.g., agricultural and wood waste, landfill gas) using biomass that would otherwise be disposed of utilizing open burning, forest accumulation, landfill (uncontrolled, gas collection with flare, gas collection with engine), spreading or composting.

34. For the reasons discussed in this decision, the emissions profile of a renewable facility should not change if or when it sells RECs under a future regulatory REC market for the purpose of demonstrating EPS compliance. Nor should RECs count towards compliance with the interim EPS by those LSEs who may purchase them for RPS compliance purposes in the future.

35. Today's determinations on how to treat null renewable power and associated RECs in the context of the interim EPS should not be construed to mean that null renewable power will be assigned a zero or low GHG emissions value in the context of the Procurement Incentive Framework we are implementing in Phase 2 of this proceeding, or the statewide GHG emissions limits adopted by the Legislature in AB 32.

36. Adopting an approach to unspecified contracts that involves the use of proxy estimates for emission rates would not further the goals of SB 1368 and would be problematic from an implementation standpoint.

37. For the reasons discussed in this decision, it is reasonable and consistent with the intent of SB 1368 to require for the interim EPS rules that LSEs specify all generation facilities underlying long-term power purchase contracts subject to the EPS.

38. A gateway screen approach to determining compliance with the interim EPS is reasonable and should be adopted.

39. Under § 8341(a), LSEs must comply with SB 1368 if they enter into any long-term financial commitment involving baseload generation, irrespective of whether (or how) this Commission reviews and approves such commitments. Under §§ 8341(a) and (b), in adopting rules and procedures to ensure compliance with the EPS, we have the flexibility under the statute to consider a range of procedural vehicles for use by those LSEs for whom we do not currently have a procurement pre-approval process in place.

40. The procedures and documentation requirements for a showing of compliance with the EPS gateway screen required of large electrical corporations, small electrical corporations, electric service providers and

community choice aggregators, as set forth in this decision, are reasonable and should be adopted.

41. No after-the-fact Attestation Letter or Advice Letter request for pre-approval of covered procurements submitted in compliance with the Interim EPS Rules should be "deemed approved," as may be permitted under the Commission's current or future Advice Letter procedures in R.98-07-038 or R.06-05-027, or their successor proceedings.

42. As discussed in this decision, consideration of a reliability exemption to the EPS or request for an "extraordinary circumstances" modification of this decision should come with a heavy burden of proof on the LSE, as it must be based on extreme (and therefore highly unlikely) circumstances.

43. As discussed in this decision, the Commission should consider any request for a reliability exemption or "extraordinary circumstances" modification on a case-by-case basis. LSE requests for pre-approval of a reliability exemption should be made by application. LSE requests to obtain "extraordinary circumstances" relief from this decision should be made by filing a petition for modification.

44. Because of the unique nature of CO_2 geological injection sequestration projects, an LSE entering into an EPS covered procurement utilizing such projects should request Commission pre-approval by application. In order to ensure that the purposes of SB 1368 are served, the LSE should be required to (1) provide documentation that the project has a reasonable and technically feasible plan that will result in a permanent sequestration of CO_2 once the injection project is operational and (2) present projections (and documentation of those projections) of net emissions over the life of the powerplant.

45. PacifiCorp's three alternative compliance tests for a showing under § 8341(d)(9)(B) are reasonable and should be adopted.

46. For the reasons discussed in this decision, our rules for demonstrating compliance with the interim EPS should not permit offsets or portfolio averaging. However, nothing in today's decision should be construed as precluding consideration of these and other compliance options in the context of Phase 2, when this Commission will be addressing the implementation of the load-based GHG emissions cap adopted in D.06-02-032.

47. Consistent with the definition of plant capacity factor provided in SB 1368 and today's decision, the term "annualized plant capacity factor" should be defined as: "the ratio of the annual amount of electricity produced, measured in kilowatt hours, divided by the annual amount of electricity the unit could have produced if it had been operated at its maximum permitted capacity, expressed in kilowatt hours.

48. In order to determine whether the plant is "designed and intended" to provide electricity at an annualized plant capacity factor of at least 60 percent, LSEs should include historical plant capacity factors for the underlying facility or facilities in their documentation of whether the EPS applies to a new long-term financial commitment (other than new plant construction).

49. SCE, PG&E and SDG&E should update their long-term procurement plans in R.06-02-013 in compliance with the EPS, as necessary, to reflect today's determinations.

50. If electric service providers and community choice aggregators are required by the Commission to file long-term procurement plans in the future, they should describe in those filings how they plan on complying with EPS.

51. CEED cites authorities which may show that the United States has a foreign policy of not entering into treaties that do not require the curbing of C02 emissions from developing nations.

52. This Commission is not proposing to enter into any treaties or agreements with foreign governments or entities.

53. When, and if, the U.S. does sign a GHG treaty or otherwise promulgates a GHG policy that is binding on the states, this Commission will be required to bring its program into compliance if there is a conflict.

54. Neither SB 1368 nor the Commission's implementation of it conflict with federal foreign policy.

55. Any party challenging the constitutional validity of the EPS under the dormant Commerce Clause bears the burden of demonstrating discrimination.

56. The EPS does not discriminate based on geographic origin.

57. Because low capacity generators are not similarly situated with plants subject to the EPS, the exemption of low capacity generators from the EPS cannot constitute discrimination against interstate commerce.

58. The Commerce Clause protects the interstate market, not particular interstate firms, from prohibitive or burdensome regulations.

59. The Commerce Clause does not require California to protect the pecuniary interests of out-of-state coal burners.

60. The EPS is an evenhanded regulation that lacks discriminatory intent or effect.

61. Whether one geographic region is impacted more than another is not relevant to a dormant Commerce Clause analysis; what is relevant is whether there is an improper discrimination against electricity produced outside California, as compared with electricity produced inside California.

62. The EPS has substantial local benefits.

63. The "burdens" on interstate commerce, alleged by CEED and others, are not "clearly excessive" in light of the substantial local benefits of the EPS.

64. Extraterritorial regulation means regulation that impacts commerce that occurs "wholly" outside the state.

65. Simply because regulation of sales to California LSEs by the EPS may affect the costs or profit of an out-of-state generation company does not make the regulation extraterritorial.

66. The EPS does not have an impermissible extraterritorial reach.

67. The EPS is valid under the dormant Commerce Clause.

68. In developing the interim EPS, the Commission has considered the effects of the standard on system reliability and overall costs to electricity customers as required under § 8341(d)(6).

69. The interim EPS fulfills both the letter and the spirit of SB 1368 by effectively "raising the bar" for the GHG emissions performance of new long-term commitments with baseload generation serving California during the transition to a statewide GHG emissions cap.

70. In order to meet the February 1, 2007 deadline established by SB `1368 for the adoption of an enforceable interim EPS, this decision should be effective immediately.

INTERIM ORDER

IT IS ORDERED that:

1. As defined in Senate Bill (SB) 1368 (Stats. 2006, ch. 598) and by today's decision, every electrical corporation, electric service provider, or community choice aggregator serving end-use customers in the state (collectively referred to

as "load-serving entities" or "LSEs") shall be subject to the greenhouse gas interim emissions performance standard rules ("Interim EPS Rules") described in this decision and set forth in Attachment 7.

2. The Interim EPS Rules presented in Attachment 7 and described in this decision shall be effective and enforceable immediately.

3. Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE) and San Diego Gas & Electric Company (SDG&E) shall submit for Commission pre-approval all procurements subject to the Interim EPS Rules ("covered procurements") as follows:

(a) For covered procurements eligible under the Renewable Portfolio Standard (RPS) program:

i. PG&E, SCE and SDG&E shall request pre-approval through RPS advice letter filings, and

ii. These advice letters shall be served on the service list in Rulemaking (R.) 06-05-027, or its successor proceeding.

iii. Should an application process be used for any particular RPS contract, or should the advice letter process set forth in Decision (D.) 03-06-071 be changed in whole or in part to an application process in the future, that application process shall automatically apply to the EPS compliance filings required of PG&E, SCE and SDG&E for RPS resources. However, if the advice letter process set forth in D.03-06-071 is modified to include procedures whereby RPS advice letters may be "deemed approved," such procedures shall not apply for the purpose of establishing EPS compliance.

(b) For covered procurements with non-RPS generation:

i. PG&E, SCE and SDG&E shall request pre-approval through the non-RPS application process established by the Commission's procurement rules in R.06-02-013, or its successor proceeding, and

ii. These applications shall be served on the service list in R.06-02-013, or its successor proceeding.

(c) For covered procurements that employ geological formation injection for carbon dioxide (CO_2) sequestration:

i. PG&E, SCE and SDG&E shall request pre-approval through the non-RPS application process established by the Commission's procurement rules in R.06-02-013, or its successor proceeding, and

ii. As part of this filing, PG&E, SCE and SDG&E shall provide documentation demonstrating that the geological formation injection project has a reasonable and technically feasible plan that will result in permanent sequestration of CO_2 once the project is operational.

iii. These applications shall be served on the service lists in R.06-02-013 and this proceeding, or their successor proceedings.

4. All LSEs other than PG&E, SCE and SDG&E are required file annual Attestation Letters, due by February 15 of each year, attesting to the Commission that the financial commitments entered into during the prior calendar year are in compliance with the EPS. The Attestation Letter shall include a certification, including the name and contract information for the LSE officer(s) certifying the following under penalty of perjury:

A. I have reviewed, or have caused to be reviewed, this compliance submittal.

B. Based on my knowledge, information, or belief, this compliance submittal does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements true.

C. Based on my knowledge, information, or belief, this compliance submittal contains all of the information required to be provided by Commission orders, rules, and regulations.

The Attestation Letter shall be filed as an advice letter and served on the service list in this proceeding, or its successor proceeding. The Attestation Letter shall be subject to the Commission procedures governing advice letter filings, which include opportunity for protests and responses. However, no Attestation Letter shall be "deemed approved" under those procedures.

Energy Division shall review the Attestation Letters and approve them if the attestation is in compliance with the Interim EPS Rules. Energy Division approval of the Attestation Letter shall only mean that the attestation is in compliance with these rules, and does not establish any other matters, e.g., it does not determine that particular plants are in actual compliance with the EPS or that financial commitments not fully disclosed in the attestation are in compliance with this decision. These LSEs shall be subject to penalties if the attestation letters are found, at a later date, to be incomplete, misleading or incorrect.

5. Except as otherwise directed under Ordering Paragraphs 6, 7 and 8, LSEs other than PG&E, SCE and SDG&E may submit advice letters during the year requesting pre-approval of a new financial commitment as EPS compliant, at their discretion. These advice letter filings, as well as any responses or protests, shall be served on the service list in this proceeding or its successor proceeding. The advice letter shall be subject to the Commission procedures governing advice letter filings, which include opportunity for protests and responses.

However, no advice letter submitted for this purpose shall be "deemed approved" under those procedures.

6. For covered procurements that employ geological formation injection for CO_2 sequestration, LSEs other than PG&E, SCE and SDG&E shall request Commission pre-approval by filing a separate application with service on the service list in this proceeding, or its successor proceeding. As part of this filing, the LSE shall provide documentation demonstrating that the geological formation injection project has a reasonable and technically feasible plan that will result in permanent sequestration of CO_2 once the injection project is operational. The LSE shall also make a showing of EPS compliance by presenting projections, and documentation of those projections, of net emissions over the life of the powerplant.

7. Any request for a reliability exemption shall require Commission pre-approval and shall be made by separate application, as follows:

A. PG&E, SCE and SDG&E shall serve such requests on the service lists in R.06-02-013 and this proceeding, or their successor proceedings, and

B. All other LSEs shall service such requests on the service list in this proceeding.

Any LSE requesting review and pre-approval of a reliability-based exemption from the EPS rule shall provide documentation demonstrating that such long-term procurements are necessary to ensure system reliability. As discussed in this decision, the Commission shall consult with the California Independent System Operator during implementation in considering the effects of requests for reliability exemptions on system reliability and overall costs to electricity customers.

8. LSEs shall not ask to be excused from the requirements of this decision for any other reason unless they can clearly demonstrate:

(a) They are facing extraordinary circumstances, catastrophic events or threat of significant financial harm not contemplated by SB 1368 and this decision, and

(b) An exemption from some requirement of this decision is necessary to significantly mitigate or eliminate the challenges posed by these circumstances.

Any requests to be excused from the requirements of this decision for such "extraordinary circumstances" must be pre-approved by the Commission and shall be made as a petition for modification of this decision and served on the service list in this proceeding, or its successor proceeding.

9. The Commission's consideration of any request for a reliability exemption or petition for modification to be excused from the requirements of this decision due to "extraordinary circumstances, catastrophic events or threat of significant financial harm" shall come with a heavy burden of proof on the LSE.

10. In the compliance submittals required under Ordering Paragraphs 3 and 4 above, all LSEs shall include a listing of the new long-term financial commitments of five years or longer they plan to enter into (SCE, PG&E and SDG&E) or have entered into during the prior year (all other LSEs) with documentation to demonstrate:

(a) That the commitments are not "covered procurements" under the Interim EPS Rules and/or

(b) For those that represent covered procurements, documentation demonstrating that such procurements are EPS-compliant.

(c) For any requested reliability-based exemptions that have been pre-approved by the Commission, a reference to the application and Commission decision number.

LSEs are advised to present documentation regarding the design and intended use of the powerplant(s) underlying the new long-term financial commitments utilizing the sources of documentation listed under § 8341(b)(4) of the Public Utilities Code, as well as any other sources of documentation that they believe will be relevant to the Commission's determination of whether the commitment represents a "covered procurement" under the Interim EPS Rules. As discussed in this decision, LSEs are required to include historical annual averages in their documentation of annualized plant capacity factors.

In documenting the emissions rates associated with covered procurements, LSEs shall comply with the Interim EPS Rules governing the calculation of those rates, which include the adopted method for cogeneration facilities.

11. In addition to other documentation required by this decision, all LSEs shall disclose the following information:

A. Any multiple contracts of less than five years with the same supplier, resource or facility, and

B. Investments in retained generation, including combined-cycle gas turbine (CCGT) powerplants deemed to be in compliance under § 8341(d)(1). This information shall describe the investment amount and type of alteration by generation facility and unit.

PG&E, SCE and SDG&E shall disclose the information listed above in their Quarterly Procurement Plan Compliance Reports established by D.02-10-062. All other LSEs shall disclose this information in the annual Attestation Letter required under Ordering Paragraph 4.

12. The advice letter procedures for the annual Attestation Letters and other compliance submittals described in this decision are adopted for the limited purpose of EPS compliance. In the event that some clarifications or

modifications to these procedures may need to be made after the effective date of this decision in order to reconcile them with updated Commission procedures for advice letter filings in R.98-07-038 or R.06-05-027, or their successor proceedings, the Assigned Commissioner shall provide such clarifications or modifications by ruling or other manner, in consultation with the assigned Administrative Law Judge (ALJ) and Energy Division.

13. Multi-jurisdictional electrical corporations may submit a proposal for alternative compliance with the Interim EPS Rules under § 8341(d)(9) of the Public Utilities Code by filing an application with service on the service list in this proceeding. In addition to the other requirements of § 8341(d)(9), the application shall show compliance with subsection (B) by showing that another state regulatory commission does one of the following:

1) requires the utility to review and report on the potential impacts of different carbon policies within its Integrated Resource Planning process; or
2) requires the utility to disclose its greenhouse gas emissions or expected change in overall emissions as a result of changes to its portfolio, including new capacity additions; or
3) adopts rules specifically regulating emissions of greenhouse gases from electricity generating facilities.

14. Unless and until the alternative compliance request is approved by the Commission, each multi-jurisdictional electrical corporation is required to demonstrate compliance with the Interim EPS Rules pursuant to the procedures set forth in Ordering Paragraphs 4-11, and include in its compliance filing a description of the method used to identify and allocate long-term financial commitments to California retail load.

15. Within sixty (60) days from the effective date of this decision, SCE, PG&E and SDG&E shall update their long-term procurement plan (LTPP) filings in

R.06-02-013 in compliance with the Interim EPS Rules, as necessary, to reflect today's determinations. If changes to the LTPP filings are necessary to show compliance with this decision, SCE, PG&E and SDG&E will file an Amendment to the LTPP, Volume 1, indicating whether the Amendment supersedes or adds to specific sections of the plan, with service on the service list in R.06-02-013.

16. As discussed in this decision, the Commission, Assigned Commissioner ALJ and/or Commission staff retain the right to data request any of the LSEs, including the electric service providers, community choice aggregators or small electrical corporations, to ask for any copies of contracts or procurement information that is deemed necessary to evaluate compliance with the EPS. Any LSE may be audited if the Commission or staff has any doubt that the LSE is forthcoming in its demonstration of EPS compliance.

17. If any of the financial commitments entered into by LSEs appear to be out of compliance with the Interim EPS Rules, the Commission may consider issuing an Order Instituting Investigation (OII) or take other appropriate action. If the Commission finds that the LSE did not comply with those rules, the Commission shall address the level of penalties in the OII proceeding or other procedural forum, as it deems appropriate.

18. Any LSE that seeks confidentiality protection for data contained in its EPS-related submittals shall follow the policies and procedures set forth in D.06-06-066.

19. This order is effective today.

Dated ______________________, at San Francisco, California.

INFORMATION REGARDING SERVICE

I have provided notification of filing to the electronic mail addresses on the attached service list.

Upon confirmation of this document's acceptance for filing, I will cause a Notice of Availability of the filed document to be served upon the service list to this proceeding by U.S. mail. The service list I will use to serve the copy Notice of Availability of the filed document is current as of today's date.

Dated December 13, 2006, at San Francisco, California.

/s/ TERESITA C. GALLARDO
Teresita C. Gallardo

************** SERVICE LIST *************
Last Update on 11-DEC-2006 by: SMJ
R0604009 LIST

************ **APPEARANCES** ************

Michael Mazur
Chief Technical Officer
3 PHASES ENERGY SERVICES, LLC
2100 SEPULVEDA BLVD., SUITE 37
MANHATTAN BEACH CA 90266
(310) 798-5275
mmazur@3phases.com
For: 3 Phases Energy Services

Donald Brookhyser
ALCANTAR & KAHL
1300 SW FIFTH AVE., SUITE 1750
PORTLAND OR 97210
(503) 402-8702
deb@a-klaw.com
For: Cogeneration Association of California

Evelyn Kahl
Attorney At Law
ALCANTAR & KAHL, LLP
120 MONTGOMERY STREET, SUITE 2200
SAN FRANCISCO CA 94104
(415) 421-4143
ek@a-klaw.com
For: Energy Producers & Users Coalition

Michael P. Alcantar
Attorney At Law
ALCANTAR & KAHL, LLP
120 MONTGOMERY STREET, SUITE 2200
SAN FRANCISCO CA 94104
(415) 421-4143
mpa@a-klaw.com
For: Cogeneration Association of California

Seema Srinivasan
Attorney At Law
ALCANTAR & KAHL, LLP
120 MONTGOMERY STREET, SUITE 2200
SAN FRANCISCO CA 94104
(415) 421-4143
sls@a-klaw.com
For: Energy Producers & Users Coalition

Paul Delaney
AMERICAN UTILITY NETWORK (A.U.N.)
10705 DEER CANYON DRIVE
ALTA LOMA CA 91737
pssed@adelphia.net
For: American Utility Network

Edward G Poole
ANDERSON DONOVAN & POOLE
601 CALIFORNIA STREET SUITE 1300
SAN FRANCISCO CA 94108
(415) 956-6413
epoole@adplaw.com
For: San Francisco Community Power

Gloria Britton
ANZA ELECTRIC COOPERATIVE, INC.
58470 HWY 371
PO BOX 391909
ANZA CA 92539
GloriaB@anzaelectric.org
For: Anza Electric Cooperative Inc.

Jenine Schenk
APS ENERGY SERVICES
400 E. VAN BUREN STREET, SUITE 750
PHOENIX AZ 85004
(602) 744-5140
jenine.schenk@apses.com
For: APS Energy Services Company

Kelly Norwood
Rates And Regulation Department
AVISTA UTILITIES
PO BOX 3727, MSC-29
SPOKANE WA 99220-3727
(509) 495-4267
kelly.norwood@avistacorp.com
For: Avista Utilities

Larry Barrett
BARRETT CONSULTING ASSOCIATES, INC.
PO BOX 60429
COLORADO SPRINGS CO 80960
(719) 634-4468
lbbarrett@adelphia.net
For: AOL Utility Corp

Bruce Mclaughlin
C.ANTHONY BRAUN
BRAUN & BLAISING, P.C.
915 L STREET, SUITE 1420
SACRAMENTO CA 95814
(916) 326-5812
mclaughlin@braunlegal.com
For: California Municipal Utilities Association

**************** SERVICE LIST ***************
Last Update on 11-DEC-2006 by: SMJ
R0604009 LIST

Janill Richards
Deputy Attorney General
CALIFORNIA ATTORNEY GENERAL'S OFFICE
1515 CLAY STREET, 20TH FLOOR
OAKLAND CA 94702
(510) 622-2130
janill.richards@doj.ca.gov
For: People of the State of California

Maureen Lennon
CALIFORNIA COGENERATION COUNCIL
595 EAST COLORADO BLVD., SUITE 623
PASADENA CA 91101
(818) 802-1004
maureen@lennonassociates.com
For: California Cogeneration Council

Avis Kowalewski
CALPINE CORPORATION
3875 HOPYARD ROAD, SUITE 345
PLEASANTON CA 94588
(925) 479-6640
kowalewskia@calpine.com

Kevin Boudreaux
CALPINE POWER AMERICA-CA, LLC
717 TEXAS AVENUE, SUITE 1000
HOUSTON TX 77002
kevin.boudreaux@calpine.com
For: Calpine Power America

Tiffany Rau
Policy And Communications Manager
CARSON HYDROGEN POWER PROJECT LLC
ONE WORLD TRADE CENTER, SUITE 1600
LONG BEACH CA 90831-1600
(562) 276-1510
tiffany.rau@bp.com
For: Carson Hydrogen Power Project LLC

Lars Kvale
CENTER FOR RESOURCE SOLUTIONS
PRESIDIO BUILDIING 97
PO BOX 39512
SAN FRANCISCO CA 94129
(415) 561-2110
lars@resource-solutions.org

Jeanne M. Sole
Deputy City Attorney
CITY AND COUNTY OF SAN FRANCISCO
1 DR. CARLTON B. GOODLETT PLACE, RM. 234
SAN FRANCISCO CA 94102
(415) 554-4619
jeanne.sole@sfgov.org
For: City and County of San Francisco

George Hanson
Department Of Water And Power
CITY OF CORONA
730 CORPORATION YARD WAY
CORONA CA 92880
(951) 739-4967
george.hanson@ci.corona.ca.us
For: City of Corona

Lynelle Lund
COMMERCE ENERGY, INC.
600 ANTON BLVD., SUITE 2000
COSTA MESA CA 92626
(714) 259-2536
llund@commerceenergy.com
For: Commerce Energy, Inc.

Tamlyn M. Hunt
Energy Program Director
COMMUNITY ENVIRONMENTAL COUNCIL
26 W. ANAPAMU ST., 2/F
SANTA BARBARA CA 93101
(805) 963-0583 122
thunt@cecmail.org
For: Community Environmental Council

Mary Lynch
CONSTELLATION ENERGY COMMODITIES GROUP
2377 GOLD MEDAL WAY
GOLD RIVER CA 95670
(916) 526-2860
mary.lynch@constellation.com

Gregory Koiser
CONSTELLATION NEW ENERGY, INC.
350 SOUTH GRAND AVENUE, SUITE 3800
LOS ANGELES CA 90071
gregory.koiser@constellation.com
For: Constellation New Energy

William H. Chen
CONSTELLATION NEW ENERGY, INC.
2175 N. CALIFORNIA BLVD., SUITE 300
WALNUT CREEK CA 94596
(925) 287-4703
bill.chen@constellation.com

Bill Lyons
CORAL POWER, LLC
4445 EASTGATE MALL, SUITE 100
SAN DIEGO CA 92121
(858) 526-2155
Bill.Lyons@shell.com
For: Coral Power LLC

R. Thomas Beach
CROSSBORDER ENERGY
2560 NINTH STREET, SUITE 213A
BERKELEY CA 94710
(510) 549-6922
tomb@crossborderenergy.com
For: the California Cogeneration Council

Jeffrey P. Gray
DAVIS WRIGHT TREMAINE, LLP
505 MONTGOMERY STREET, SUITE 800
SAN FRANCISCO CA 94111-6533
(415) 276-6500
jeffgray@dwt.com
For: Calpine Corporation

Ann L. Trowbridge
Attorney At Law
DAY CARTER & MURPHY, LLP
3620 AMERICAN RIVER DRIVE, SUITE 205
SACRAMENTO CA 95864
(916) 570-2500
atrowbridge@daycartermurphy.com
For: California Clean DG Coalition

Daniel W. Douglass
Attorney At Law
DOUGLASS & LIDDELL
21700 OXNARD STREET, SUITE 1030
WOODLAND HILLS CA 91367
(818) 961-3001
douglass@energyattorney.com

Gregory S.G. Klatt
DOUGLASS & LIDDELL
411 E. HUNTINGTON DRIVE, STE. 107-356
ARCADIA CA 91006
(818) 961-3002
klatt@energyattorney.com
For: Alliance for Retail Energy Markets

Jane E. Luckhardt
Attorney At Law
DOWNEY BRAND LLP
555 CAPITOL MALL, 10TH FLOOR
SACRAMENTO CA 95814
(916) 444-1000
jluckhardt@downeybrand.com
For: Sacramento Municipal Utility District

William W. Westerfield, Iii
Attorney At Law
ELLISON, SCHNEIDER & HARRIS L.L.P.
2015 H STREET
SACRAMENTO CA 95814
(916) 447-2166
www@eslawfirm.com
For: Sierra Pacific Power Company

Jedediah J. Gibson
Attorney At Law
ELLISON, SCHNEIDER & HARRIS LLP
2015 H STREET
SACRAMENTO CA 95814
(916) 447-2166
jjg@eslawfirm.com
For: LS Power Generation, LLC

Andrew Brown
Attorney At Law
ELLISON, SCHNEIDER & HARRIS, LLP
2015 H STREET
SACRAMENTO CA 95814
(916) 447-2166
abb@eslawfirm.com
For: Constellation New Energy, Inc.,Constellation Energy Commodities Group, Inc.Constellation Genrat

Greggory L. Wheatland
Attorney At Law
ELLISON, SCHNEIDER & HARRIS, LLP
2015 H STREET
SACRAMENTO CA 95814
(916) 447-2166
glw@eslawfirm.com
For: LS Power, Inc.

Adrian Pye
ENERGY AMERICA, LLC
ONE STAMFORD PLAZA, EIGHTH FLOOR
263 TRESSER BLVD.
STAMFORD CT 06901
(416) 590-3290
adrian.pye@na.centrica.com
For: Energy America

Virgil Welch
Climate Campaign Coordinator
ENVIRONMENTAL DEFENSE
1107 9TH STREET, SUITE 540
SACRAMENTO CA 95814
(916) 492-7078
vwelch@environmentaldefense.org

Ronald Moore
GOLDEN STATE WATER/BEAR VALLEY ELECTRIC
630 EAST FOOTHILL BOULEVARD
SAN DIMAS CA 91773
(909) 394-3600 X 682
rkmoore@gswater.com
For: Golden State Water/Bear Valley Electric

James D. Squeri
Attorney At Law
GOODIN MACBRIDE SQUERI RITCHIE & DAY LLP
505 SANSOME STREET, STE 900
SAN FRANCISCO CA 94111
(415) 392-7900
jsqueri@gmssr.com
For: Powerex Corp.

Brian T. Cragg
Attorney At Law
GOODIN, MACBRIDE, SQUERI, RITCHIE & DAY
505 SANSOME STREET, SUITE 900
SAN FRANCISCO CA 94111
(415) 392-7900
bcragg@gmssr.com
For: Independent Energy Producers Association

Gregg Morris
GREEN POWER INSTITUTE
2039 SHATTUCK AVENUE, STE 402
BERKELEY CA 94704
(510) 644-2700
gmorris@emf.net

Norman A. Pedersen
Attorney At Law
HANNA AND MORTON, LLP
444 SOUTH FLOWER STREET, NO. 1500
LOS ANGELES CA 90071
(213) 430-2510
npedersen@hanmor.com
For: Southern California Generation Coalition

Ian Carter
Policy Coordinator-North America
INTERNATIONAL EMISSIONS TRADING ASSN.
350 SPARKS STREET, STE. 809
OTTAWA ON K1R 7S8
CANADA
(613) 594-3912
carter@ieta.org
For: International Emissions Trading Association

Dennis M.P. Ehling
Attorney At Law
KIRKPATRICK & LOCKHART NICHOLSON GRAHAM
10100 SANTA MONICA BLVD., 7TH FLOOR
LOS ANGELES CA 90067
(310) 552-5000
dehling@klng.com
For: City of Vernon

William H. Booth
Attorney At Law
LAW OFFICES OF WILLIAM H. BOOTH
1500 NEWELL AVENUE, 5TH FLOOR
WALNUT CREEK CA 94596
(925) 296-2460
wbooth@booth-law.com
For: California Large Energy Consumers Association

Diana L. Lee
Legal Division
RM. 4300
505 VAN NESS AVE
San Francisco CA 94102 3298
(415) 703-4342
dil@cpuc.ca.gov

C. Susie Berlin
BARRY F. MCCARTHY
Attorney At Law
MC CARTHY & BERLIN, LLP
100 PARK CENTER PLAZA, SUITE 501
SAN JOSE CA 95113
(408) 288-2080
sberlin@mccarthylaw.com
For: Northern California Power Agency

Barry F. Mccarthy
Attorney At Law
MCCARTHY & BERLIN, LLP
100 PARK CENTER PLAZA, SUITE 501
SAN JOSE CA 95113
(408) 288-2080
bmcc@mccarthylaw.com
For: Northern California Generation Coalition

Michael A. Yuffee
MCDERMOTT WILL & EMERY LLP
600 THIRTEENTH STREET, N.W.
WASHINGTON DC 20005-3096
(202) 756-8066
myuffee@mwe.com
For: Morgan Stanley Capital Group Inc

Kerry Hattevik
MIRANT CORPORATION
696 WEST 10TH STREET
PITTSBURG CA 94565
(925) 427-3483
kerry.hattevik@mirant.com
For: Mirant Corporation

Joy A. Warren
Attorney At Law
MODESTO IRRIGATION DISTRICT
PO BOX 4060
MODESTO CA 95352
(209) 526-7389
joyw@mid.org

John Jensen
JOHN DUTCHER
President
MOUNTAIN UTILITIES
PO BOX 205
KIRKWOOD CA 95646
(209) 258-7444
jjensen@kirkwood.com
For: Mountain Utilities

Sara Steck Myers
Attorney At Law
122 28TH AVENUE
SAN FRANCISCO CA 94121
(415) 387-1904
ssmyers@att.net
For: Center for Energy Efficiency and Renewable Technologies

Audrey Chang
NATURAL RESOURCES DEFENSE COUNCIL
111 SUTTER STREET, 20TH FLOOR
SAN FRANCISCO CA 94104
(415) 875-6100
achang@nrdc.org

E.J. Wright
OCCIDENTAL POWER SERVICES, INC.
5 GREENWAY PLAZA, SUITE 110
HOUSTON TX 77046
(562) 624-3309
ej_wright@oxy.com

Brian K. Cherry
Director Regulatory Relations
PACIFIC GAS AND ELECTRIC COMPANY
PO BOX 770000 MC B10C
SAN FRANCISCO CA 94177-0001
bkc7@pge.com
For: Pacific Gas and Electric Company

Christopher J. Warner
PACIFIC GAS AND ELECTRIC COMPANY
77 BEALE STREET
SAN FRANCISCO CA 94105
(415) 973-6695
cjw5@pge.com
For: Pacific Gas and Electric

Kyle L. Davis
PACIFICORP
825 NE MULTNOMAH,
PORTLAND OR 97232
(503) 813-6601
kyle.l.davis@pacificorp.com
For: PacifiCorp

Natalie Hocken, Esq.
PACIFICORP
LLOYD CENTER TOWER
825 NE MULTNOMAH
PORTLAND OR 97232
Natalie.Hocken@PacifiCorp.com

Shay Labray
Manager, Regulatory
PACIFICORP
825 NE MULTNOMAH, SUITE 2000
PORTLAND OR 97232
(503) 813-6176
shayleah.labray@pacificorp.com
For: Pacificorp

Thomas Darton
PILOT POWER GROUP, INC.
9320 CHESAPEAKE DRIVE, SUITE 112
SAN DIEGO CA 92123
(858) 627-9577
tdarton@pilotpowergroup.com
For: Pilot Power Group

Robert W. Marshall
General Manager
PLUMAS-SIERRA RURAL ELECTRIC CO-OP
73233 STATE ROUTE 70, STE A
PORTOLA CA 96122-7064
marshall@psln.com
For: Plumas-Sierra Rural Electric Coop

Rick C. Noger
PRAXAIR PLAINFIELD, INC.
2711 CENTERVILLE ROAD, SUITE 400
WILMINGTON DE 19808
(925) 866-6809
rick_noger@praxair.com
For: Praxair Plainfield, Inc.

J. Andrew Hoerner
REDEFINING PROGRESS
1904 FRANKLIN STREET
OAKLAND CA 94612
(510) 507-4820
hoerner@redefiningprogress.org

Lisa G. Urick
Attorney At Law
SAN DIEGO GAS & ELECTRIC COMPANY
101 ASH STREET
SAN DIEGO CA 92101
(619) 699-5070
Lurick@sempra.com
For: San Diego Gas & Electric/SoCal Gas

Steve Rahon
LEE SCHAVRIEN
Director, Tariff & Regulatory Accounts
SAN DIEGO GAS & ELECTRIC COMPANY
8330 CENTURY PARK COURT, CP32C
SAN DIEGO CA 92123-1548
lschavrien@semprautilities.com
For: San Diego Gas & Electric Company

Dan Hecht
SEMPRA ENERGY
101 ASH STREET
SAN DIEGO CA 92101
(203) 355-5417
dhecht@sempratrading.com

Daniel A. King
SEMPRA ENERGY
101 ASH STREET, HQ13
SAN DIEGO CA 92101
(619) 696-4350
daking@sempra.com

Symone Vongdeuane
SEMPRA ENERGY SOLUTIONS
101 ASH STREET, HQ09
SAN DIEGO CA 92101-3017
(619) 696-4996
svongdeuane@semprasolutions.com
For: Sempra Energy Solutions

Theodore Roberts
Attorney At Law
SEMPRA GLOBAL
101 ASH STREET, HQ 13D
SAN DIEGO CA 92101-3017
(619) 699-5111
troberts@sempra.com
For: Sempra Global/Sempra Energy Solutions

Darrell Soyars
Manager-Resource Permitting&Strategic
SIERRA PACIFIC RESOURCES
6100 NEIL ROAD
RENO NV 89520-0024
(775) 834-4744
dsoyars@sppc.com
For: Sierra Pacific Resources

Akbar Jazayeiri
Director Of Revenue & Tarriffs
SOUTHERN CALIFORNIA EDISON COMPANY
2244 WALNUT GROVE AVE. ROOM 390
ROSEMEAD CA 91770
akbar.jazayeri@sce.com
For: Southern California Edison Company

Annette Gilliam
Attorney At Law
SOUTHERN CALIFORNIA EDISON COMPANY
2244 WALNUT GROVE AVENUE
ROSEMEAD CA 91770
(626) 302-4880
annette.gilliam@sce.com
For: Southern California Edison

Lad Lorenz
V.P. Regulatory Affairs
SOUTHERN CALIFORNIA GAS COMPANY
601 VAN NESS AVENUE, SUITE 2060
SAN FRANCISCO CA 94102
(415) 202-9986
llorenz@semprautilities.com

Richard Helgeson
SOUTHERN CALIFORNIA PUBLIC POWER AUTHORI
225 S. LAKE AVE., SUITE 1250
PASADENA CA 91101
(626) 793-9364
rhelgeson@scppa.org
For: Southern California Public Power Authority

Andrea Weller
STRATEGIC ENERGY
3130 D BALFOUR RD., SUITE 290
BRENTWOOD CA 94513
(916) 759-7052
aweller@sel.com
For: Strategic Energy

Jennifer Chamberlin
STRATEGIC ENERGY, LLC
3130 D BALFOUR ROAD, STE 290
BRENTWOOD CA 94513
(925) 969-1031
jchamberlin@sel.com
For: Strategic Energy, LLC

Dan Silveria
SURPRISE VALLEY ELECTRIC COOPERATIVE
PO BOX 691
ALTURAS CA 96101
(916) 233-3511
dansvec@hdo.net
For: Surprise Valley Electric Cooperative

Keith R. Mccrea
Attorney At Law
SUTHERLAND, ASBILL & BRENNAN, LLP
1275 PENNSYLVANIA AVE., N.W.
WASHINGTON DC 20004-2415
(202) 383-0705
keith.mccrea@sablaw.com
For: California Manufacturers & Technology Assn.

F. Jackson Stoddard
Legal Division
RM. 5040
505 VAN NESS AVE
San Francisco CA 94102 3298
(415) 703-5888
fjs@cpuc.ca.gov

Marcel Hawiger
THE UTILITY REFORM NETWORK
711 VAN NESS AVENUE, SUITE 350
SAN FRANCISCO CA 94102
(415) 929-8876
marcel@turn.org

Nina Suetake
Attorney At Law
THE UTILITY REFORM NETWORK
711 VAN NESS AVE., STE 350
SAN FRANCISCO CA 94102
(415) 929-8876
nsuetake@turn.org

Cliff Chen
UNION OF CONCERNED SCIENTIST
2397 SHATTUCK AVENUE, STE 203
BERKELEY CA 94704
(510) 843-1872
cchen@ucsusa.org

John Galloway
UNION OF CONCERNED SCIENTISTS
2397 SHATTUCK AVENUE, SUITE 203
BERKELEY CA 94704
(510) 809-1564
jgalloway@ucsusa.org

Eric Guidry
WESTERN RESOURCE ADVOCATES
2260 BASELINE ROAD, SUITE 200
BOULDER CO 80304
(303) 444-1188
eguidry@westernresources.org
For: Western Resource Advocates

Joseph M. Karp
Attorney At Law
WINSTON & STRAWN LLP
101 CALIFORNIA STREET
SAN FRANCISCO CA 94111
(415) 591-1529
jkarp@winston.com
For: California Cogeneration Council

Karen Bowen
Attorney At Law
WINSTON & STRAWN LLP
101 CALIFORNIA STREET
SAN FRANCISCO CA 94111
(415) 544-6305
kbowen@winston.com
For: Mirant California, LLCMirant Delta,LLC, and Mirant Potrero, LLC

Lisa A. Cottle
Attorney At Law
WINSTON & STRAWN LLP
101 CALIFORNIA STREET, 39TH FLOOR
SAN FRANCISCO CA 94111
(415) 544-1105
lcottle@winston.com
For: Mirant California, LLC,Mirant Delta, LLC, and Mirant Potrero, LLC

********** **STATE EMPLOYEE** ***********

Michael Scheible
Deputy Executive Officer
CALIFORNIA AIR RESOURCES BOARD
1001 I STREET
SACRAMENTO CA 95677
(916) 324-6021
mscheibl@arb.ca.gov
For: California Air Resources Board

B. B. Blevins
Executive Director
CALIFORNIA ENERGY COMMISSION
1516 9TH STREET, MS-39
SACRAMENTO CA 95814
bblevins@energy.state.ca.us
For: California Energy Commission

Karen Griffin
Executive Office
CALIFORNIA ENERGY COMMISSION
1516 9TH STREET, MS 39
SACRAMENTO CA 95814
(916) 654-4833
kgriffin@energy.state.ca.us

Lisa Decarlo
Staff Counsel
CALIFORNIA ENERGY COMMISSION
1516 9TH STREET MS-14
SACRAMENTO CA 95814
(916) 654-5195
ldecarlo@energy.state.ca.us

Pierre H. Duvair
CALIFORNIA ENERGY COMMISSION
1516 NINTH STREET, MS-41
SACRAMENTO CA 95814
(916) 653-8685
pduvair@energy.state.ca.us

Judith B. Sanders
Attorney At Law
CALIFORNIA INDEPENDENT SYSTEM OPERATOR
151 BLUE RAVINE ROAD
FOLSOM CA 95630
(916) 608-7143
jsanders@caiso.com
For: CAISO

Julie Gill
External Affairs Manager
CALIFORNIA INDEPENDENT SYSTEM OPERATOR
151 BLUE RAVINE ROAD
FOLSOM CA 95630
(916) 361-2221
jgill@caiso.com
For: CAISO

Mary Mcdonald
Director Of State Affairs
CALIFORNIA INDEPENDENT SYSTEM OPERATOR
151 BLUE RAVINE ROAD
FOLSOM CA 95630
(916) 802-3576
For: CAISO

Philip D. Pettingill
CALIFORNIA INDEPENDENT SYSTEM OPERATOR
151 BLUE RAVINE ROAD
FOLSOM CA 95630
(916) 608-7241
ppettingill@caiso.com
For: CAISO

Grant A. Rosenblum
Staff Counsel
CALIFORNIA ISO
151 BLUE RAVINE ROAD
FOLSOM CA 95630
(916) 608-7138
grosenblum@caiso.com

Eugene Cadenasso
Energy Division
AREA 4-A
505 VAN NESS AVE
San Francisco CA 94102 3298
(415) 703-1214
cpe@cpuc.ca.gov

Theresa Cho
Executive Division
RM. 5207
505 VAN NESS AVE
San Francisco CA 94102 3298
(415) 703-2682
tcx@cpuc.ca.gov

Matthew Deal
Energy Division
AREA 4-A
505 VAN NESS AVE
San Francisco CA 94102 3298
(415) 703-5649
mjd@cpuc.ca.gov

Julie A. Fitch
Division of Strategic Planning
RM. 5203
505 VAN NESS AVE
San Francisco CA 94102 3298
(415) 355-5552
jf2@cpuc.ca.gov

Meg Gottstein
Administrative Law Judge
PO BOX 210/21496 NATIONAL STREET
VOLCANO CA 95689
(209) 296-4979
gottstein@volcano.net

Meg Gottstein
Administrative Law Judge Division
RM. 2106
505 VAN NESS AVE
San Francisco CA 94102 3298
(415) 703-4802
meg@cpuc.ca.gov

Judith Ikle
Energy Division
RM. 4012
505 VAN NESS AVE
San Francisco CA 94102 3298
(415) 703-1486
jci@cpuc.ca.gov
For: Energy Resources Branch

Sara M. Kamins
Energy Division
AREA 4-A
505 VAN NESS AVE
San Francisco CA 94102 3298
(415) 703-1388
smk@cpuc.ca.gov

Jonathan Lakritz
Administrative Law Judge Division
RM. 5020
505 VAN NESS AVE
San Francisco CA 94102 3298
(415) 703-5235
jol@cpuc.ca.gov

James Loewen
Energy Division
320 WEST 4TH STREET SUITE 500
Los Angeles CA 90013
(213) 620-6341
loe@cpuc.ca.gov

Jaclyn Marks
Division of Strategic Planning
RM. 5119
505 VAN NESS AVE
San Francisco CA 94102 3298
(415) 703-2778
jm3@cpuc.ca.gov

Lainie Motamedi
Division of Strategic Planning
RM. 5119
505 VAN NESS AVE
San Francisco CA 94102 3298
(415) 703-1764
lrm@cpuc.ca.gov

Deborah Slon
Deputy Attorney General, Environment
OFFICE OF THE ATTORNEY GENERAL
1300 I STREET, 15TH FLOOR
SACRAMENTO CA 95814
(916) 327-7851
deborah.slon@doj.ca.gov

Kristin Ralff Douglas
Division of Strategic Planning
RM. 5119
505 VAN NESS AVE
San Francisco CA 94102 3298
(415) 703-2826
krd@cpuc.ca.gov

Nancy Ryan
Executive Division
RM. 5217
505 VAN NESS AVE
San Francisco CA 94102 3298
(415) 703-1823
ner@cpuc.ca.gov

Bill Lockyer
KEN/ALEX
State Attorney General
STATE OF CALIFORNIA, DEPT OF JUSTICE
PO BOX 944255
SACRAMENTO CA 94244-2550
(916) 445-9555
ken.alex@doj.ca.gov

Don Schultz
Division of Ratepayer Advocates
RM. SCTO
770 L STREET, SUITE 1050
Sacramento CA 95814
(916) 327-2409
dks@cpuc.ca.gov

Donald R. Smith
Division of Ratepayer Advocates
RM. 4209
505 VAN NESS AVE
San Francisco CA 94102 3298
(415) 703-1562
dsh@cpuc.ca.gov

Merideth Sterkel
Energy Division
AREA 4-A
505 VAN NESS AVE
San Francisco CA 94102 3298
(415) 703-1873

Christine S. Tam
Division of Ratepayer Advocates
RM. 4209
505 VAN NESS AVE
San Francisco CA 94102 3298
(415) 355-5556
tam@cpuc.ca.gov

Charlotte TerKeurst
Administrative Law Judge Division
RM. 5117
505 VAN NESS AVE
San Francisco CA 94102 3298
(415) 703-3124
cft@cpuc.ca.gov

********* **INFORMATION ONLY** **********

Marc D. Joseph
ADAMS BRADWELL JOSEPH & CARDOZO
601 GATEWAY BLVD. STE 1000
SOUTH SAN FRANCISCO CA 94080
(650) 589-1660
mdjoseph@adamsbroadwell.com
For: California Unions for Reliable Energy&Coalition of California Utility Employees

Gloria D. Smith
ADAMS, BROADWELL, JOSEPH & CARDOZO
601 GATEWAY BLVD., SUITE 1000
SOUTH SAN FRANCISCO CA 94080
(650) 589-1660
gsmith@adamsbroadwell.com

Karen Terranova
ALCANTAR & KAHL, LLP
120 MONTGOMERY STREET, STE 2200
SAN FRANCISCO CA 94104
(415) 421-4143
filings@a-klaw.com

Annie Stange
ALCANTAR & KAHL
1300 SW FIFTH AVE., SUITE 1750
PORTLAND OR 97210
(503) 402-8702
sas@a-klaw.com

Nora Sheriff
Attorney At Law
ALCANTAR & KAHL, LLP
120 MONTGOMERY STREET, SUITE 2200
SAN FRANCISCO CA 94104
(415) 421-4143
mts@cpuc.ca.gov

John Laun
APOGEE INTERACTIVE, INC.
1220 ROSECRANS ST., SUITE 308
SAN DIEGO CA 92106
(619) 840-4804
jlaun@apogee.net

John R. Redding
ARCTURUS ENERGY CONSULTING
44810 ROSEWOOD TERRACE
MENDOCINO CA 95460
(707) 937-0878
johnrredding@earthlink.net

Steven S. Schleimer
Director,Compliance & Regulatory Affairs
BARCLAYS BANK, PLC
200 PARK AVENUE, FIFTH FLOOR
NEW YORK NY 10166
steven.schleimer@barclayscapital.com

Barbara R. Barkovich
BARKOVICH & YAP, INC.
44810 ROSEWOOD TERRACE
MENDOCINO CA 95460
(707) 937-6203
brbarkovich@earthlink.net

Curt Barry
717 K STREET, SUITE 503
SACRAMENTO CA 95814
(916) 449-6171
curt.barry@iwpnews.com

Reed V. Schmidt
Vice President
BARTLE WELLS ASSOCIATES
1889 ALCATRAZ AVENUE
BERKELEY CA 94703
(510) 653-3399
rschmidt@bartlewells.com
For: California City-County Street Light Association

Ryan Wiser
BERKELEY LAB
MS-90-4000
ONE CYCLOTRON ROAD
BERKELEY CA 94720
(510) 486-5474
rhwiser@lbl.gov

nes@a-klaw.com

Monica A. Schwebs, Esq.
BINGHAM MCCUTCHEN LLP
SUITE 210
1333 N. CALIFORNIA BLVD.
WALNUT CREEK CA 94596
(925) 937-8000
monica.schwebs@bingham.com

Greg Blue
140 MOUNTAIN PKWY.
CLAYTON CA 94517
(925) 323-3612
greg.blue@sbcglobal.net

David Branchcomb
BRANCHCOMB ASSOCIATES, LLC
9360 OAKTREE LANE
ORANGEVILLE CA 95662
(916) 988-5676
david@branchcomb.com

Dallas Burtraw
1616 P STREET, NW
WASHINGTON DC 20036
(202) 328-5087
burtraw@rff.org

Dan Adler
Director, Tech And Policy Development
CALIFORNIA CLEAN ENERGY FUND
582 MARKET ST., SUITE 1015
SAN FRANCISCO CA 94104
(415) 986-4590
Dan.adler@calcef.org

Michael Mccormick
CALIFORNIA CLIMATE ACTION REGISTRY
515 S. FLOWER ST. SUITE 1640
LOS ANGELES CA 90071
(213) 891-1444 106
mike@climateregistry.org

Holly B. Cronin
State Water Project Operations Div
CALIFORNIA DEPARTMENT OF WATER RESOURCES
PO BOX 219000
3310 EL CAMINO AVE., LL-90
SACRAMENTO CA 95821
(916) 574-0708
hcronin@water.ca.gov

CALIFORNIA ENERGY MARKETS
517-B POTRERO AVENUE
SAN FRANCISCO CA 94110
(415) 552-1764 X 17
cem@newsdata.com

Karen Norene Mills
Attorney At Law
CALIFORNIA FARM BUREAU FEDERATION
2300 RIVER PLAZA DRIVE
SACRAMENTO CA 95833
(916) 561-5655
kmills@cfbf.com

CALIFORNIA ISO
LEGAL AND REGULATORY DEPARTMENT
151 BLUE RAVINE ROAD
FOLSOM CA 95630
e-recipient@caiso.com

Avis Kowalewski
Director Of Regulatory Affairs
CALPINE CORPORATION
3875 HOPYARD ROAD, SUITE 345
PLEASANTON CA 94588
(925) 479-7311
kowalewskia@calpine.com

Olof Bystrom
Director, Western Energy
CAMBRIDGE ENERGY RESEARCH ASSOCIATES
555 CALIFORNIA STREET, 3RD FLOOR
SAN FRANCISCO CA 94104
(415) 568-2214
obystrom@cera.com

Jen Mcgraw
CENTER FOR NEIGHBORHOOD TECHNOLOGY
PO BOX 14322
SAN FRANCISCO CA 94114
(415) 644-0877
jen@cnt.org

Daren Chan
PO BOX 770000, MAIL CODE B9A
SAN FRANCISCO CA 94177
d1ct@pge.com

************** SERVICE LIST *************
Last Update on 11-DEC-2006 by: SMJ
R0604009 LIST

Jan Pepper
CLEAN POWER MARKETS, INC.
PO BOX 3206
418 BENVENUE AVENUE
LOS ALTOS CA 94024
(650) 949-5719
pepper@cleanpowermarkets.com

Lisa Decker
Counsel
CONSTELLATION ENERGY GROUP, INC.
111 MARKET PLACE, SUITE 500
BALTIMORE MD 21202
(410) 468-3792
lisa.decker@constellation.com

Clyde Murley
CONSULTANT
600 SAN CARLOS AVENUE
ALBANY CA 94706
(510) 528-8953
clyde.murley@comcast.net

Christopher A. Hilen
Attorney At Law
DAVIS WRIGHT TREMAINE LLP
505 MONTGOMERY STREET, SUITE 800
SAN FRANCISCO CA 94111-6533
(415) 276-6573
christopherhilen@dwt.com

Balwant S. Purewal
DEPARTMENT OF WATER RESOURCES
3310 EL CAMINO AVE., LL-90
SACRAMENTO CA 95821
(916) 574-0668
bpurewal@water.ca.gov

William F. Dietrich
Attorney At Law
DIETRICH LAW
2977 YGNACIO VALLEY ROAD, 613
WALNUT CREEK CA 94598-3535
(415) 297-2356
dietrichlaw2@earthlink.net

Donald C. Liddell, P.C.
DOUGLASS & LIDDELL
2928 2ND AVENUE
SAN DIEGO CA 92103
(619) 993-9096
liddell@energyattorney.com

Joseph M. Paul
Senior Corporate Counsel
DYNEGY, INC.
2420 CAMINO RAMON, SUITE 215
SAN RAMON CA 94583
(925) 866-4909
Joe.paul@dynegy.com

Mahlon Aldridge
ECOLOGY ACTION
PO BOX 1188
SANTA CRUZ CA 95060
(831) 426-5925 116
emahlon@ecoact.org

Lynn Haug
ELLISON, SCHNEIDER & HARRIS, LLP
2015 H STREET
SACRAMENTO CA 95816
(916) 447-2166
lmh@eslawfirm.com

Shaun Ellis
2183 UNION STREET
SAN FRANCISCO CA 94123
(415) 771-7571 317
sellis@fypower.org

Tom Hamilton
Managing Partner
ENERGY CONCIERGE SERVICES
321 MESA LILA RD
GLENDALE CA 91208
(818) 306-5099
THAMILTON5@CHARTER.NET

Cynthia Mitchell
ENERGY ECONOMICS, INC.
530 COLGATE COURT
RENO NV 89503
(775) 324-5300
ckmitchell1@sbcglobal.net

Carolyn M. Kehrein
ENERGY MANAGEMENT SERVICES
1505 DUNLAP COURT
DIXON CA 95620-4208
(707) 678-9506
cmkehrein@ems-ca.com

************** SERVICE LIST *************
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Kevin J. Simonsen
ENERGY MANAGEMENT SERVICES
646 EAST THIRD AVENUE
DURANGO CO 81301
(970) 259-1748
kjsimonsen@ems-ca.com

Saeed Farrokhpay
FEDERAL ENERGY REGULATORY COMMISSION
110 BLUE RAVINE RD., SUITE 107
FOLSOM CA 95630
(916) 294-0322
saeed.farrokhpay@ferc.gov

Norman J. Furuta
FEDERAL EXECUTIVE AGENCIES
333 MARKET STREET, 10TH FLOOR, MS 1021A
SAN FRANCISCO CA 94105-2195
(415) 977-8808
norman.furuta@navy.mil

Michel Florio
Attorneys At Law
711 VAN NESS AVE., STE. 350
SAN FRANCISCO CA 94102
(415) 929-8876
mflorio@turn.org

Janine L. Scancarelli
FOLGER LEVIN & KAHN LLP
275 BATTERY STREET, 23RD FLOOR
SAN FRANCISCO CA 94111
(415) 986-2800
jscancarelli@flk.com

Kyle D. Boudreaux
FPL GROUP
700 UNIVERSE BLVD., JES/JB
JUNO BEACH FL 33408
(561) 691-7358
kyle_boudreaux@fpl.com

Rachel Mcmahon
Senior Policy Associate
GLOBAL GREEN USA
2218 MAIN STREET
SANTA MONICA CA 90404
(310) 581-2700
rmcmahon@globalgreen.org

Curtis L. Kebler
GOLDMAN, SACHS & CO.
2121 AVENUE OF THE STARS
LOS ANGELES CA 90067
(310) 407-5619
curtis.kebler@gs.com

Joseph F. Wiedman
Attorney At Law
GOODIN MACBRIDE SQUERI RITCHIE & DAY,LLP
505 SANSOME STREET, SUITE 900
SAN FRANCISCO CA 94111
(415) 392-7900
jwiedman@gmssr.com

Denise Hill
Director
4004 KRUSE WAY PLACE, SUITE 150
LAKE OSWEGO OR 97035
(503) 675-3816
Denise_Hill@transalta.com
For: Market Access & Trade Policy Transalta Energy Marketing (US) Inc.

Brenda Lemay
Director Of Project Development
HORIZON WIND ENERGY
1600 SHATTUCK, SUITE 222
BERKELEY CA 94709
(510) 704-8152
brenda.lemay@horizonwind.com

Steven Kelly
INDEPENDENT ENERGY PRODUCERS ASSN
1215 K STREET, SUITE 900
SACRAMENTO CA 95814-3947
(916) 448-9499
steven@iepa.com

Jody S. London
JODY LONDON CONSULTING
PO BOX 3629
OAKLAND CA 94609
(510) 459-0667
jody_london_consulting@earthlink.net

Carol Jolly
PO BOX 585
CHESTERFIELD MA 01012
(413) 296-4254
cajollyco@verizon.net

Edward J. Tiedemann
Attorney At Law
KRONICK, MOSKOVITZ, TIEDEMANN & GIRARD
400 CAPITOL MALL, 27TH FLOOR
SACRAMENTO CA 95814-4416
(916) 321-4500
etiedemann@kmtg.com
For: Placer County Water Agency & Kings River Conservation District

Diane I. Fellman
Attorney At Law
LAW OFFICES OF DIANE I. FELLMAN
234 VAN NESS AVENUE
SAN FRANCISCO CA 94102
(415) 703-6000
diane_fellman@fpl.com

Edward Vine
LAWRENCE BERKELEY NATIONAL LABORATORY
BUILDING 90-4000
BERKELEY CA 94720
(510) 486-6047
elvine@lbl.gov

Karen Lindh
LINDH & ASSOCIATES
7909 WALERGA ROAD, NO. 112, PMB119
ANTELOPE CA 95843
(916) 729-1562
karen@klindh.com

Barry Lovell
15708 POMERADO RD., SUITE 203
POWAY CA 92064
bjl@bry.com

Audra Hartmann
LS POWER GENERATION
980 NINTH STREET, SUITE 1420
SACRAMENTO CA 95814
(916) 441-6242
ahartmann@lspower.com

John W. Leslie
Attorney At Law
LUCE, FORWARD, HAMILTON & SCRIPPS, LLP
11988 EL CAMINO REAL, SUITE 200
SAN DIEGO CA 92130
(858) 720-6352
jleslie@luce.com

Richard Mccann, Ph.D
M. CUBED
2655 PORTAGE BAY, SUITE 3
DAVIS CA 95616
(530) 757-6363
rmccann@umich.edu

Brian M. Jones
M. J. BRADLEY & ASSOCIATES, INC.
47 JUNCTION SQUARE DRIVE
CONCORD MA 01742
bjones@mjbradley.com

Erin M. Murphy
MCDERMOTT WILL & EMERY LLP
600 THIRTEENTH STREET, N.W.
WASHINGTON DC 20005
(202) 756-8000
emmurphy@mwe.com

Ann G. Grimaldi
MCKENNA LONG & ALDRIDGE LLP
101 CALIFORNIA STREET, 41ST FLOOR
SAN FRANCISCO CA 94111
(415) 267-4000
agrimaldi@mckennalong.com
For: Center for Energy and Economic Development

Paul M. Seby
TIMOTHY R. ODIL
MCKENNA LONG & ALDRIDGE LLP
1875 LAWRENCE STREET, SUITE 200
DENVER CO 80202
(303) 634-4000
pseby@mckennalong.com
For: Center for Energy and Economic Development

Timothy R. Odil
MCKENNA LONG & ALDRIDGE LLP
1875 LAWRENCE STREET, SUITE 200
DENVER CO 80202
(303) 634-4000
todil@mckennalong.com
For: Center for Energy and Economic Development

Cathy S. Woollums
MIDAMERICAN ENERGY HOLDINGS COMPANY
106 EAST SECOND STREET
DAVENPORT IA 52801
(563) 333-9008
cswoollums@midamerican.com

Christopher J. Mayer
MODESTO IRRIGATION DISTRICT
1231 11TH STREET
MODESTO CA 95354
(209) 526-7430
chrism@mid.org

Richard Smith
MODESTO IRRIGATION DISTRICT
1231 11TH STREET
MODESTO CA 95352-4060
(209) 526-7463
richards@mid.org

Roger Vanhoy
MODESTO IRRIGATION DISTRICT
1231 11TH STREET
MODESTO CA 95354
(209) 526-7464
rogerv@mid.org

Steven Huhman
MORGAN STANLEY CAPITAL GROUP INC.
2000 WESTCHESTER AVENUE
PURCHASE NY 10577
(914) 225-1592
steven.huhman@morganstanley.com

MRW & ASSOCIATES, INC.
1999 HARRISON STREET, SUITE 1440
OAKLAND CA 94612
(510) 834-1999
mrw@mrwassoc.com

Devra Wang
NATURAL RESOURCES DEFENSE COUNCIL
111 SUTTER STREET, 20TH FLOOR
SAN FRANCISCO CA 94104
(415) 875-6100
dwang@nrdc.org

Eric Wanless
NATURAL RESOURCES DEFENSE COUNCIL
111 SUTTER STREET, 20TH FLOOR
SAN FRANCISCSO CA 95104
(415) 875-6100
ewanless@nrdc.org

Sheryl Carter
NATURAL RESOURCES DEFENSE COUNCIL
111 SUTTER STREET, 20TH FLOOR
SAN FRANCISCO CA 94104
(415) 875-6100
scarter@nrdc.org

Frank Luchetti
NEVADA DIV. OF ENVIRONMENTAL PROTECTION
901 S. STEWART ST., SUITE 4001
CARSON CITY NV 89701
(775) 687-9345
fluchetti@ndep.nv.gov

Howard V. Golub
NIXON PEABODY LLP
2 EMBARCADERO CENTER, STE. 2700
SAN FRANCISCO CA 94111
(415) 984-8200
hgolub@nixonpeabody.com

Scott Tomashefsky
NORTHERN CALIFORNIA POWER AGENCY
180 CIRBY WAY
ROSEVILLE CA 95678-6420
(916) 781-4291
scott.tomashefsky@ncpa.com

Martin A. Mattes
NOSSAMAN, GUTHNER, KNOX & ELLIOTT, LLP
50 CALIFORNIA STREET, 34TH FLOOR
SAN FRANCISCO CA 94111
(415) 398-3600
mmattes@nossaman.com

Jesus Arredondo
NRG ENERGY INC.
4600 CARLSBAD BLVD.
CARLSBAD CA 99208
(916) 275-7493
jesus.arredondo@nrgenergy.com

Tim Hemig
NRG ENERGY, INC.
1819 ASTON AVENUE, SUITE 105
CARLSBAD CA 92008
(760) 710-2144
tim.hemig@nrgenergy.com

Sam Sadler
OREGON DEPARTMENT OF ENERGY
625 NE MARION STREET
SALEM OR 97301-3737
(503) 373-1034
samuel.r.sadler@state.or.us

Lisa Schwartz
Senior Analyst
ORGEON PUBLIC UTILITY COMMISSION
PO BOX 2148
SALEM OR 97308-2148
(503) 378-8718
lisa.c.schwartz@state.or.us

Ed Lucha
Project Coordinator
PACIFIC GAS AND ELECTRIC COMPANY
PO BOX 770000, MAIL CODE: B9A
SAN FRANCISCO CA 94177
(415) 973-3872
ell5@pge.com

Grace Livingston-Nunley
Assistant Project Manager
PACIFIC GAS AND ELECTRIC COMPANY
PO BOX 770000 MAIL CODE B9A
SAN FRANCISCO CA 94177
(415) 973-4304
gxl2@pge.com

Sebastien Csapo
Project Manager
PACIFIC GAS AND ELECTRIC COMPANY
MAIL CODE B9A
PO BOX 770000
SAN FRANCISCO CA 94177
sscb@pge.com

Soumya Sastry
PACIFIC GAS AND ELECTRIC COMPANY
MAIL CODE B9A
PO BOX 770000
SAN FRANCISCO CA 94177
(415) 973-3295
svs6@pge.com

Stephanie La Shawn
PACIFIC GAS AND ELECTRIC COMPANY
MAIL CODE B9A
77 BEALE STREET, RM. 996B
SAN FRANCISCO CA 94105
(415) 973-8063
S1L7@pge.com

Valerie J. Winn
PACIFIC GAS AND ELECTRIC COMPANY
PO BOX 770000, B9A
SAN FRANCISCO CA 94177-0001
(415) 973-3839
vjw3@pge.com

Carla Peterman
1815 BLAKE ST., APT. A
BERKELEY CA 94703
(917) 538-6667
carla.peterman@gmail.com

Jasmin Ansar
PG&E
MAIL CODE B24A
PO BOX 770000
SAN FRANCISCO CA 94177
jxa2@pge.com

Jonathan Forrester
PG&E
MAIL CODE N13C
PO BOX 770000
SAN FRANCISCO CA 94177
JDF1@PGE.COM

Lisa Weinzimer
California Energy Reporter
PLATTS
695 NINTH AVENUE, NO. 2
SAN FRANCISCO CA 94118
(415) 387-1025
lisa_weinzimer@platts.com

Veronique Bugnion
POINT CARBON
205 SEVERN RIVER RD
SEVERNA PARK MD 21146
(443) 822-1301
vb@pointcarbon.com

Brian Potts
SUITE 700
ONE SOUTH PINCKNEY STREET
MADISON WI 53703
(608) 257-7470
bhpotts@michaelbest.com

Carl Pechman
POWER ECONOMICS
901 CENTER STREET
SANTA CRUZ CA 95060
cpechman@powereconomics.com

Kenny Swain
POWER ECONOMICS
901 CENTER STREET
SANTA CRUZ CA 95060
(813) 427-9990
kswain@powereconomics.com

Karen Mcdonald
POWEREX CORPORATION
1400,
666 BURRAND STREET
VANCOUVER BC V6C 2X8
CANADA

(604) 895-7030
karen.mcdonald@powerex.com

Harvey Eder
PUBLIC SOLAR POWER COALITION
1218 12TH ST., 25
SANTA MONICA CA 90401
(310) 393-2589
harveyederpspc.org@hotmail.com

James Ross
RCS, INC.
500 CHESTERFIELD CENTER, SUITE 320
CHESTERFIELD MO 63017
(636) 530-9544
jimross@r-c-s-inc.com

Arno Harris
RECURRENT ENERGY, INC.
220 HALLECK ST., SUITE 220
SAN FRANCISCSO CA 94129
(415) 298-7096
arno@recurrentenergy.com

Richard Cowart
REGULATORY ASSISTANCE PROJECT
50 STATE STREET, SUITE 3
MONTPELIER VT 05602
(802) 223-8199
rapcowart@aol.com

Brian Mcquown
RELIANT ENERGY
7251 AMIGO ST., SUITE 120
LAS VEGAS NV 89119
(702) 407-4861
bmcquown@reliant.com

Ellen Wolfe
RESERO CONSULTING
9289 SHADOW BROOK PL.
GRANITE BAY CA 95746
(916) 781-4533
ewolfe@resero.com

Clark Bernier
RLW ANALYTICS
1055 BROADWAY, SUITE G
SONOMA CA 95476
(707) 939-8823 X 19
clark.bernier@rlw.com

Steven Moss
SAN FRANCISCO COMMUNITY POWER COOP
2325 3RD STREET, SUITE 344
SAN FRANCISCO CA 94120
(415) 643-9578
steven@moss.net

Michael A. Hyams
Power Enterprise-Regulatory Affairs
SAN FRANCISCO PUBLIC UTILITIES COMM
1155 MARKET ST., 4TH FLOOR
SAN FRANCISCO CA 94103
(415) 554-1513
mhyams@sfwater.org

Mike Sandler
4731 LA VILLA MARINA, UNIT B
MARINA DEL REY CA 90292
(707) 529-4620
msandler@pair.com

Colin Petheram
Director-Regulatory
SBC CALIFORNIA
140 NEW MONTGOMERY ST., SUITE 1325
SAN FRANCISCO CA 94105
(415) 778-1255
cp284@att.com

Phillip J. Muller
SCD ENERGY SOLUTIONS
436 NOVA ALBION WAY
SAN RAFAEL CA 94903
(415) 479-1710
philm@scdenergy.com

Adrian E. Sullivan
SEMPRA ENERGY
REGULATORY LAW DEPARTMENT
101 ASH STREET, HQ13D
SAN DIEGO CA 92101
(619) 699-5097
asullivan@sempra.com

Aimee M. Smith
Attorney At Law
SEMPRA ENERGY
101 ASH STREET HQ13
SAN DIEGO CA 92101
(619) 699-5042
amsmith@sempra.com

**************** SERVICE LIST ****************
Last Update on 11-DEC-2006 by: SMJ
R0604009 LIST

Rasha Prince
SAN DIEGO GAS & ELECTRIC
555 WEST 5TH STREET, GT14D6
LOS ANGELES CA 90013
(213) 244-5141
rprince@semprautilities.com

Yvonne Gross
Regulatory Policy Manager
SEMPRA ENERGY
HQ08C
101 ASH STREET
SAN DIEGO CA 92103
(619) 696-2075
ygross@sempraglobal.com

Douglas Brooks
Nevada Power Company
SIERRA PACIFIC POWER COMPANY
6226 WEST SAHARA AVENUE
LAS VEGAS NV 89151
dbrooks@nevp.com

Elena Mello
SIERRA PACIFIC POWER COMPANY
6100 NEIL ROAD
RENO NV 89520
(775) 834-5696
emello@sppc.com

Trevor Dillard
SIERRA PACIFIC POWER COMPANY
6100 NEIL ROAD
RENO NV 89520
regulatory@sierrapacific.com

Case Administration
SOUTHERN CALIFORNIA EDISON COMPANY
2244 WALNUT GROVE AVE., RM. 370
ROSEMEAD CA 91770
(626) 302-4875
case.admin@sce.com

Kevin Fox
STOEL RIVES LLP
900 SW FIFTH AVENUE, SUITE 2600
PORTLAND OR 97204
(503) 294-9139
ktfox@stoel.com

Alexia C. Kelly
THE CLIMATE TRUST
65 SW YAMHILL STREET, SUITE 400
PORTLAND OR 97204
(503) 238-1915
akelly@climatetrust.org

Hayley Goodson
Attorney At Law
THE UTILITY REFORM NETWORK
711 VAN NESS AVENUE, SUITE 350
SAN FRANCISCO CA 94102
(415) 929-8876
hayley@turn.org

Matthew Freedman
Attorney At Law
THE UTILITY REFORM NETWORK
711 VAN NESS AVENUE, SUITE 350
SAN FRANCISCO CA 94102
(415) 929-8876
freedman@turn.org

Roger Pelote
THE WILLIAMS COMPANY, INC.
12736 CALIFA STREET
VALLEY VILLAGE CA 91607
(818) 761-5954
roger.pelote@williams.com

Khurshid Khoja
Associate
THELEN REID BROWN RAYSMAN & STEINER
101 SECOND STREET, SUITE 1800
SAN FRANCISCO CA 94105
(415) 369-7643
kkhoja@thelenreid.com

Mark C. Trexler
TREXLER CLIMATE+ENERGY SERVICES, INC.
529 SE GRAND AVE,M SUITE 300
PORTLAND OR 97214-2232
(503) 231-2727
mtrexler@climateservices.com

Andrew J. Van Horn
VAN HORN CONSULTING
12 LIND COURT
ORINDA CA 94563
(925) 254-3358
andy.vanhorn@vhcenergy.com

Alan Comnes
WEST COAST POWER
3934 SE ASH STREET
PORTLAND OR 97214
(503) 239-6913
alan.comnes@nrgenergy.com