Comments of the Natural Resources Defense Council (NRDC) and the Union of Concerned Scientists (UCS) on the *Implementation of SB 1368 Emission Performance Standard* Staff Issue Identification Paper

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The Natural Resources Defense Council (NRDC) and the Union of Concerned Scientists (UCS) appreciate the opportunity to offer these comments on the California Energy Commission's (CEC or Commission) *Implementation of SB 1368 Emission Performance Standard* Staff Issue Identification Paper, Publication #CEC-700-2006-011 (Staff Paper).

NRDC is a non-profit membership organization with a long-standing interest in minimizing the societal costs of the reliable electricity services that Californians demand. We focus on representing our more than 131,000 California members' interest in receiving affordable energy services and reducing the environmental impact of California's electricity consumption. UCS is a leading science-based non-profit working for a healthy environment and a safer world. Its Clean Energy Program examines the benefits and costs of the country's energy use and promotes energy solutions that are sustainable both environmentally and economically.

We commend the CEC for the leadership role it has taken in establishing a greenhouse gas (GHG) emission performance standard (EPS), which the Commission advanced as one of its primary recommendations in the 2005 *Integrated Energy Policy Report*. We strongly support the Commission's efforts to design and implement the EPS, which is an essential regulation that will protect Californians from the significant financial and reliability risks associated with additional investments in highly carbon-intensive generating technologies and help meet California's GHG reduction goals. We thank the Commission for the opportunity to comment on the Staff Paper regarding the implementation of the EPS, now adopted into law by Senate Bill (SB) 1368. We commend CEC staff for compiling a comprehensive issue paper, and we look forward to discussing our comments with the CEC and other interested parties at the workshop on December 8, 2006.

To ensure a uniform statewide standard, we encourage the CEC to adopt an EPS that is consistent, to the extent possible, with the EPS that will be adopted by the California Public Utilities Commission (CPUC) by February 1, 2007. Although the EPS for the POUs to be adopted by the CEC is different from the EPS for the IOUs and other LSEs to be adopted by the CPUC, SB 1368 intended to create a statewide EPS and thus many of the issues being considered by the CEC are similar to those already considered by the CPUC in its implementation of the EPS. For reference, we have attached our most recent set of comments on the CPUC final workshop report in the CPUC proceeding on the topic.[1] We note that the CPUC has not yet adopted its final decision adopting the regulations for its implementation of SB 1368 (a draft decision is expected in mid-December).

We have organized our comments following the outline and list of questions presented in the Staff Paper.

Affected Entities & Financial Commitments

Long-Term Financial Commitment

Question 3.1

Does it only apply to an investment in a newly constructed facility or does it also apply to the repowering of an existing facility? Should there be a size or monetary threshold below which the phrase would not apply?

The EPS applies to all new LSE long-term financial commitments, including newly constructed utility-owned generation facilities, repowering and major renovations of utility-owned generation, as well as new and renewed contracts. Major renovations and repowering each fall under SB 1368's definition of a "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" (Section 8340(j), emphasis added). As long as the repowering or major renovation of a baseload generation facility is intended to extend plant life by five or more years, the investment should trigger the EPS. We suggest the following definition, proposed by Administrative Law Judge Meg Gottstein in the CPUC proceeding: "Any investment that is intended to extend the life of one or more units of an existing baseload powerplant for five years or more." This manner of defining repowering and renovations is much simpler and more consistent with the intent of the statute than setting either a size or monetary threshold.

Question 3.2

How does the intent of the legislation guide our choice?

As the Staff Paper acknowledges on page 6, SB 1368 clearly intends to protect all Californian electricity consumers from the significant financial and reliability risks of

[1] CPUC Rulemaking 06-04-009, "Opening Comments and Legal Brief on Final Workshop Report and Staff Recommendations Regarding the Greenhouse Gas Emissions Performance Standard of the Natural Resources Defense Council (NRDC), The Utility Reform Network (TURN), the Union of Concerned Scientists (UCS), and the Western Resource Advocates (WRA)," October 18, 2006; and "Reply Comments and Legal Brief on Final Workshop Report and Staff Recommendations Regarding the Greenhouse Gas Emissions Performance Standard of the Natural Resources Defense Council (NRDC), The Utility Reform Network (TURN), the Union of Concerned Scientists (UCS), and the Western Resource Advocates (WRA)," October 27, 2006.

reliance on high GHG-emitting resources. The implementation of this statute should not allow for ways to circumvent the law's requirements.

We urge the Commission **not** to define repowers or renovations as solely consisting of investments that result in a net increase in rated capacity. Under this interpretation, an existing high-emitting power plant with emissions above the EPS would not be subject to the EPS upon repowering or renovation if it did not increase the plant's rated capacity, although the new financial commitment would still present significant financial and reliability risks to California customers. Just as there is no basis in SB 1368 for a substantive size threshold (Section 8341(e) is clear that the EPS should apply to "*any* baseload generation supplied under the long-term financial commitment," emphasis added), there is also no reason to apply a size threshold to repowering or renovations. SB 1368 clearly intends the EPS to apply to new *financial commitments*.

Question 3.3

Is it generally clear that Joint Power arrangements constitute ownership under the statute?

No; JPAs are contracts. As the Staff Paper points out, in a JPA, the participating POUs contract with the JPA for the output of the powerplant. In any case, new and renewed JPAs constitute financial commitments that would be subject to the EPS.

The Staff Paper's statement that "the statute uses slightly different language to describe the coverage of ownership and contracts" (p. 7) is misleading. The only place that SB 1368 differentiates between ownership and contracts is in defining a "long-term financial commitment" in section 8340(j). Since "new ownership investments" and "new or renewed contracts" are both included in this definition, it is clear that the statute intends the EPS to apply to ***all*** new long-term financial commitments.

Question 3.4

Can one infer any legislative intent from the fact that the definition of "long-term financial commitment" refers to both "new and renewed" contracts but to only a "new" ownership investment? Does omission of the term "renewed" provide guidance for the types of activities that should be covered under "new ownership investment"?

As we explain above, the intent of SB 1368 is clearly to protect California customers from long-term financial and reliability risks from reliance on high-emitting resources. The legislation's reference to "new" ownership investments simply clarifies that it the EPS is not intended to apply retroactively to existing utility-owned powerplants that do not have new investments made in them. Making a new investment (repowering or major renovation) in an existing utility-owned powerplant would constitute a new ownership investment in that powerplant that is analogous to signing a new or renewed contract with a non-utility-owned facility. ***All*** new long-term financial commitments must meet the EPS.

Question 3.5

Does the investment have to affect a power plant's operation and production of greenhouse gases to subject it to the standard?

No. Similar to our response to Question 3.2, an existing high-emitting power plant with emissions above the EPS would still present significant financial and reliability risks to California customers, even if an investment were to decrease overall GHG emissions but not to a level below the standard.

Question 3.6

Should the investment definition be tied to the size of the power plant modifications, similar to the 50 MW size threshold used for State siting permits?

No. See our response to Question 3.2. SB 1368 is clear that the EPS should apply to ***any*** baseload generation.

Question 3.7

Should the definition of investment exclude expenditures made to comply with another law or regulation, such as unit retrofits to comply with once-through cooling limitations?

SB 1368 is clear that all existing combined-cycle gas turbine (CCGT) powerplants are deemed in compliance with the standard (see Section 8341(e)(1)). If once-through cooling or other requirements are required for an existing CCGT, it is clear that these facilities will still be deemed to comply with the standard.

Question 3.8

If a plant must be modified to comply with changing environmental regulations (or be shuttered for failure to comply), does the statute imply such plants be closed rather than modified if they cannot meet the EPS? If not, how does one reconcile two potentially competing environmental goals and determine which should take precedence?

See response to Question 3.7. Existing CCGTs are deemed in compliance with SB 1368, so any changing environmental regulation for these facilities will not change the outcome. For other existing powerplants that have a capacity factor of greater than 60 percent, SB 1368 is clear that "any" baseload generation supplying a long-term financial commitment must meet the standard, so any new investment that is intended to prolong the life of the plant by five or more years should trigger the EPS. If the plant has emissions Powerplants that do not have a capacity factor greater than 60 percent are unaffected by the EPS.

Question 3.9

Would a stringent investment definition discourage owners from undertaking modernization or maintenance investments? If the process for reviewing proposed *financial investments is lengthy or covers many types of investments, would the cost of complying outweigh the benefits of maintaining or modernizing the plant?*

The EPS compliance process should be designed to be as simple as possible without compromising the intent of the statute. We look forward to discussing options to do this with the CEC and other parties.

Question 3.10

If an investment significantly improves the GHG performance of a facility, but not below the performance standard, should it be prohibited? A POU might be interested in financing the retrofit of existing facility units to make partial improvements to the facility's GHG profile. Does the law intend to prohibit such investments?

See our response to Question 3.5. If the overall emissions of the baseload facility will still exceed the standard due to the investment, it still presents significant financial and reliability risks and should not pass the EPS.

Question 3.11

Does the statute require, allow, or prohibit defining "new ownership investment" as any investment that extends the life of a baseload power plant for more than 5 years? Does the statutory clause "term of five or more years" apply to ownership or contracts?

We support this definition of "new ownership investments" for existing facilities as "any investment that extends the life of a baseload power plant for 5 *or more* years" as being entirely consistent with the statute. The term "five or more years" applies to the length of new or renewed contracts, as well as to the length of time for which ownership investments are intended to extend the life of a baseload power plant.

Question 3.12

Should expenditures excluded for complying with New Source Review requirements, such as routine replacement and repair, not be considered investments?

The determination of what constitutes "new ownership investments" for the purpose of implementing SB 1368 should stand alone from any other regulations. Thus, those investments classified as routine replacement and repair under New Source Review requirements should **not** be exempted from compliance with the EPS, and should still be considered financial commitments that are subject to the EPS. By defining new ownership investments for existing facilities as we describe above, the CEC will also by default define routine maintenance as any investment that does not extend the life of a plant by 5 years.

Question 3.13

What constitutes routine replacement and repair and how should such activities be defined in the regulations?

See response to Question 3.12.

Issues for "new or renewed long-term contracts" for procurement of baseload generation"

Question 3.13(2)

> *What documentation will be required for POUs and the Energy Commission to distinguish between baseload and non-baseload facilities? Does the 60% threshold apply to a facility's produced power or grid-supplied power? Would the statute's "design and intended" language apply to the facility's original or current capacity factor? Are there other factors that need to be considered to accurately identify baseload facilities?*

We recommend that the Commission refer to the suggested documentation listed in SB 1368, Section 8341(c)(3):

> In determining whether a long-term financial commitment is for baseload generation, the Energy Commission shall consider the design of the powerplant and the intended use of the powerplant, as determined by the Energy Commission based upon the electricity purchase contract, any certification received from the Energy Commission, any other permit or certificate necessary for the operation of the powerplant, including a certificate of public convenience and necessity, any procurement approval decision for the load-serving entity, and any other matter the Energy Commission determines is relevant under the circumstances.

We also emphasize that documentation of compliance with the EPS must allow for an "apples-to-apples" comparison of emissions rates of covered resources. This is most appropriately accomplished through the use of designed and intended heat rates, **<u>not</u>** full load heat rates, as suggested by PG&E in the CPUC proceeding. To determine the level at which the EPS should be set, parties in the CPUC proceeding examined data which presents emissions levels corresponding to the actual operations of power plants. However, 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 (as plant output decreases, the corresponding heat rate increases, and emissions are proportional to heat rate for the same fuel type).

To be consistent with SB 1368, the 60% threshold should be applied to a facility's total produced power. This application of the EPS to underlying facilities is fully consistent with the requirements of SB 1368:

> Section 8341 (a): No load-serving entity or local publicly owned electric utility may enter into a long-term financial commitment unless **<u>any baseload generation</u>** supplied under the long-term financial commitment complies with the greenhouse gases emission performance standard… *(emphasis added)*

Baseload generation is defined in Section 8340 (a) 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.” And powerplant is defined in Section 8340 (m) as “a facility for the generation of electricity, and includes one or more generating units at the same location.” Thus, the determination of whether the EPS applies to a resource should consistently be made based on the characteristics and greenhouse gas emissions of the powerplant, without regard to how much electricity is provided to the grid or not.

For existing facilities, the statute’s “designed and intended” language should apply to the facility’s current capacity factor (perhaps calculating a three-year average capacity factor for this purpose). It should be relatively easy to determine this from existing information about the plant’s operation. For new facilities, “designed and intended” should take into account the design of the facility, and the purpose for which it is intended to be used.

Question 3.14

> *Under the statute, should JPAs be treated as a contract for electricity procurement or as an ownership interest?*

See our response to Question 3.3. JPAs are long-term contracts.

<u>Emissions Performance Standard</u>

Coal

Question 4.1

> *Could any coal-fired or advance coal-fired technologies meet the EPS?*

Yes; if those coal-fired or advanced coal-fired (or any other fuel) technologies also captured and permanently disposed of enough of their emissions to meet the standard. We stress that the EPS is non-fuel specific; any fuel technology that would be able to reduce its emissions below the standard would meet the EPS.

Question 4.2

> *Would a demonstration project for advance coal-fired technologies and/or CO2 sequestration need to operate at more than 60% capacity factor or for more than 5 years, requiring the unit(s) to meet the EPS?*

SB 1368 in no way calls for a research and development exemption. SB 1368’s determination that “Carbon dioxide that is captured from the emissions of a powerplant and that is permanently disposed of in geological formations 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” (Section 8341(e)(6)) simply details how sequestered GHG emissions are factored into the calculations of a facility’s emissions rate in order to determine compliance, not to exempt any facility.

Each and every facility that is designed and intended to operate at a capacity factor of 60 percent or higher (and to which a new long-term financial commitment is made) must be required to meet the EPS. Though we believe that the Commission should support research, development, and deployment of advanced technologies, it must not do so at the expense of potentially undermining the EPS and exposing Californians to significant reliability and financial risks.

Petroleum Coke

Question 4.4

Could any petroleum coke or advance petroleum coke-burning technologies meet the EPS?

Yes; if those petroleum coke or advanced petroleum coke-burning (or any other fuel) technologies also captured and permanently disposed of enough of their emissions to meet the standard. We stress that the EPS is non-fuel specific; any fuel technology that would be able to reduce its emissions below the standard would meet the EPS.

Cogeneration/Combined Heat & Power

Although no questions were posed in this section of the Staff Paper, we outline here our supported methodology for crediting the thermal load that is **used** in cogen facilities. We stress that cogen facilities should only be credited for the thermal load that is in fact used, not thermal output that is simply generated but not used.

We recommend the use of the following formula, which is similar to the Energy Producers and Users Coalition and Cogeneration Association of California (EPUC/CAC) proposed methodology presented in the CPUC final staff workshop report:

$$EmissionRate = \frac{TotalEmissions}{kWh_{electricity} + \frac{kWh}{3412Btu}\left(Btu_{used\_output}\right)}$$

The *TotalEmissions* should be calculated using the designed and intended carbon intensity of the fuel and turbine characteristics or could be measured at the plant for existing facilities. The $kWh_{electricity}$ delivered is the electrical output at the plant in normal operating conditions.

The Btu_{used_output} value is the heat *used* onsite in processes or heating and should be estimated from plant/process/building designs; the heating load being met by the cogen facility and the heat supplied to local processes by the cogen plant should be known by the design engineers. Waste heat and unused useable heat should not be included in the Btu_{used_output} value. This value should be calculated on a case-by-case basis, and should not be a universally assumed fraction. This is the major clarification/difference between our proposed approach and the EPUC/CAC approach; the Btu value used for the thermal energy in our proposal represents *used* heat, not available heat. If there is more usable heat available than heat needed and used, only the heat that is actually used should be included in the calculation.

It is important to note that the conversion factor in an output based approach used to credit used thermal load must be the 3412 Btu/kWh and *not* the heat rate of the generator. Using the heat rate of the generator is not appropriate in this context as it reflects electric generation efficiency and is not a conversion factor. Because this is an output-based approach, and because total emissions reflect all the fuel burned regardless of conversion efficiencies, using heat rates for converting used heat to kWh would double count the efficiency losses.

This "conversion" approach has the advantage of being more accurate in calculating the actual emissions rate of the cogen facility, since it takes into account the actual thermal output that is used, which is information that should be available from design engineers. The "emissions avoided" approach (e.g., assuming an 80% efficient boiler that would have otherwise provided the same thermal output) inherently requires more detailed estimates, especially if the facility is new.

Waste Fuels

Question 4.6

> *What criteria are used to define a waste fuel? Does the use of a waste fuel result in zero GHG emissions or would there be a formula to calculate avoided GHG emissions? Would current emissions of GHG from a flare that would be avoided with the use of the fuel in a power plant be considered in net emission calculations? How would the GHG emissions be calculated for a unit using a mixture of waste fuels and fossil fuels? How should non-cogeneration qualifying facility units using a waste or renewable fuels calculate net emissions, or should they receive a credit for being a qualifying facility?*

Section 8341(e)(5) of SB 1368 states: "In calculating the emissions of greenhouse gases by facilities generating electricity from biomass, biogas, or landfill gas energy, the Energy Commission shall consider net emissions from the process of growing, processing, and generating the electricity from the fuel source."

Landfill gas, biomass, and biogas digestion are considered eligible renewable resources under the California Renewables Portfolio Standard (RPS).[2] The greenhouse gas mitigation benefits of these renewable resources have been well documented in the CPUC proceeding on the EPS, as well as at the CEC and other state venues. As we also recommended to the CPUC, we urge the CEC to make a one-time determination at this time that all RPS-eligible renewables are deemed in compliance with the EPS.[3] This approach is consistent with SB 1368, Section 8341(e)(5), which simply requires the CEC to "consider" net emissions. For the purposes of this rulemaking, the CEC should impute a zero emissions value to all RPS-eligible renewables. This one-time consideration and

[2] Municipal solid waste conversion technology that uses a non-combustion process and meets a number of other requirements is also considered an RPS-eligible resource, but no such facilities are currently operating in the U.S.

[3] We stress the importance of the distinction between deemed compliance and an exemption; although this may seem like a minor nuance, this distinction should continue to be made in order to accurately represent the treatment of renewables in the EPS – namely, that they do in fact meet the standard and are not actually exempt from the rule.

determination of deemed compliance for renewables will increase administrative simplicity by eliminating the need for each renewable resource to individually demonstrate an emissions rate lower than the EPS.

The other waste fuel resources identified in the Staff Paper are not “biomass, biogas, or landfill gas” resources. Since facilities that use petroleum coke and municipal solid waste do not have greenhouse gas reduction benefits, their smokestack emissions should be treated “as is,” without imputing any avoided emissions value. SB 1368 only requires the examination of net emissions generally of a powerplant itself and <u>not</u> the lifecycle emissions of a fuel upstream or downstream of a powerplant.

The emissions rate of any facility using a mixture of waste fuels and fossil fuels should be treated in the same manner. To calculate the overall emissions rate of a mixed-fuel facility, the portion of generation that is derived from any waste fuels that are RPS-eligible should be assigned a net emissions value of zero. The emissions due to generation from other waste fuels should not be subject to a net emissions calculation.

Greenhouse Gases
Question 4.7

> *If the CPUC adopts a CO2-only EPS in its regulations, either as a first step or as a reasonable approximation of electricity production GHG emissions, should the Energy Commission follow suit? Should the EPS be phased to address the other GHG emissions from electricity production at a later time? Should we develop a factual record of non-CO2 emission rates from electricity production to be able to set a CO2 and non-CO2 EPS?*

Section 8340(g) of SB 1368 intends the EPS to apply to the emissions of ***all*** GHGs. The Energy Commission should strive for consistency with the CPUC EPS regulations to the extent practicable. If the CPUC initially adopts a CO2-only EPS, the Energy Commission should do the same. However, we support the phased inclusion of non-CO2 GHGs in the implementation of the EPS, as all GHGs are intended by SB 1368 to be included in the EPS. As the Staff Paper correctly notes on page 14, non-CO2 GHGs have much higher per-unit global warming potentials.

State agencies will also need to determine methodologies and protocols to address non-CO2 greenhouse gas emissions from electricity generation as part of their implementation of AB 32. However, this process will probably require coordination among multiple state agencies over an extended period of time. Considering the relatively short timeframe of the instant rulemaking, addressing non-CO2 greenhouse gases independently of the CPUC does not seem prudent within the context of short-term EPS implementation. We suggest that the CEC, in coordination with the CPUC, begin to develop a factual record of non-CO2 emission rates from electricity production to aid in the phased addition of non-CO2 emissions in the statewide EPS.

Renewables/Non-Renewables Blended Contracts
Question 4.8

Should the POU GHG standard be different than that adopted for the IOUs because of the added legal options to meet their requirement? How are the net emissions calculated in blended contracts?

The POU GHG standard established and enforced by the CEC must first and foremost be consistent with SB 1368. The statute does **not** allow in any way for blending of emissions, as each individual underlying baseload resource must meet the EPS.

The CPUC's final staff proposal also supports this point, by recommending that "each covered unit must qualify" in multi-unit contracts (Section 7)b) of CPUC staff proposal). Although the CPUC staff proposal recommended an exemption to this rule to allow emissions blending of the resources in a firmed baseload renewable contract, we maintain that this blending runs counter to SB 1368's direction that "[n]o 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" (Section 8341(a), emphasis added). SB 1368 is clear that the standard is to apply to each facility underlying a contract.

Emissions blending should never be allowed, as it would open a significant loophole that would completely compromise the integrity of the standard. We are extremely concerned that this provision will allow high-emitting resources that would never pass the standard alone (such as pulverized coal) to be blended with zero-emitting renewable resources. By allowing the emissions of a high-carbon emitting resource to be "diluted" by a cleaner resource, emissions blending would circumvent the ability of the EPS to reduce the significant reliability and financial risks associated with high carbon-emitting resources. Although this sort of tradeoff between high- and low-emitting resources may be appropriate in the GHG cap system to be implemented in California under AB 32, there is no place for emissions blending in the EPS.

In addition, the CEC EPS for the POUs should be consistent with the EPS implemented by the CPUC for IOUs and other jurisdictional load-serving entities (LSEs). Though POUs and IOUs are subject to different rules and regulatory treatment under the RPS, NRDC/UCS do not discern any features particular to POU contracting methods with renewable resources that would justify differential treatment of blended renewables contracts for POUs and IOUs under the EPS.

Unit/Facility Electricity Production

Question 4.9

If the power comes from a facility, does every unit on site have to meet the EPS? Does every unit at a facility have to meet the 60% capacity factor in order to be included in the EPS compliance calculations? If the power comes from a contract, does every unit or facility in the contract site have to meet the EPS?

Assuming that the new financial commitment under consideration is for five or more years, each unit at a facility with a capacity factor of at least 60% must meet the EPS for the entire facility to qualify. The same principle applies to contracts: any unit that is part of a contract and has a capacity factor of at least 60% must meet the EPS for the entire contract to qualify. Any unit with a capacity factor of less than 60% is not subject to the EPS and does not need to be included in EPS compliance calculations.

Calculation of Biomass, Biogas or Landfill Net Emissions
Question 4.10

> *What should be included in the net emissions calculations for "growing, processing and generating electricity from the fuel source"? Should the landfill gas net emissions calculations include GHG sources such as diesel used to dump, compact and cover the municipal solid waste?*

Although NRDC/UCS recognize life-cycle analysis as a best practice for determining the overall emissions impact of a particular generation source, this type of detailed emissions accounting analysis is highly academic, time-consuming, and potentially contentious. It is also unlikely to change the status of RPS-eligible resources such as landfill gas under the EPS. Both the CPUC and SB 1368 are clear that biomass and landfill gas resources should be allowed to pass the EPS. In light of this, and considering the relatively short timeframe established for EPS implementation, the Energy Commission should not divert its time or resources to engage in life-cycle emissions analysis within this rulemaking.

As we describe in our answer to Question 4.6, we suggest the CEC make a one-time upfront determination that the emissions from RPS-eligible resources are much lower than the maximum permitted by the EPS, and that all such resources are deemed in compliance with the standard.

Unspecified Sources of Long-Term Contracts
Question 4.12

> *Should the Energy Commission standard address this POU market model regardless of what the CPUC does for ESPs?*

SB 1368 requires the CEC (along with the CPUC) to "address long-term purchases of electricity from unspecified sources in a manner consistent with this chapter" (Section 8341(e)(8)). The CEC would be in conflict with the statute's requirement if it were to ignore unspecified resources in implementing the EPS.

ESPs in the CPUC proceeding have indicated that they do not sign contracts of greater than five years, and thus contend that the EPS need not address unspecified resources. However, the CPUC is nevertheless likely to address the unspecified resources, which nonetheless still represent a potential long-term source of electricity supply for LSEs in general. We have recommended that unspecified resources be carefully considered to avoid creating perverse incentives for increased use of unspecified contracts. For consistency with the CPUC's regulations, the CEC must address unspecified sources, especially considering the fact that they are already part of the POU long-term resource mix. As the Staff Paper notes, "POUs have been using long-term contracts with marketers or portfolio managers to meet their small baseload acquisitions." (p. 16).

Reliability and Cost Considerations

Question 4.13

> *Is this a basis for having a case-by-case review of financial commitments that might be made for reliability and/or consumer cost considerations?*

SB 1368 does not specifically call for exemptions for reliability and cost considerations. Section 8341(e)(7) stipulates: "In *adopting and implementing* the greenhouse gases emission performance standard, the Energy Commission…shall *consider* the effects of the standard on system reliability and overall costs to electricity customers" (emphasis added). We are committed, along with the Commission, to maintaining and enhancing the reliability of California's electricity grid. We also consider one of the primary purposes of the EPS to be protecting Californians against long-term reliability and financial risks. The reliability protections of SB 1368 are reflected in its provisions that it only apply to commitments to baseload generation of more than five years. Therefore, we do not believe that a reliability or cost exemption for the EPS is necessary because the standard itself is designed as protection from these risks.

Short-term reliability is not affected by the EPS, since the standard applies only to long-term contracts of over five years and does not address economic dispatch issues. Peaking or shoulder plants (which have an annual average capacity factor of less than 60 percent) that are needed for reliability purposes are likewise not subject to the EPS. In addition, the EPS only determines which baseload plants can be included in new long-term commitments. It does not affect the operation of these plants in the short term. If a plant is intended to run at an average of 60% or greater capacity factor over several years, then it *should* be required to meet the EPS, since it could potentially present long-term reliability and financial risks.

We believe that our recommendations for implementing the EPS will ensure that the standard is designed specifically to avoid reliability and overall cost concerns, as well as to protect Californians from long-term reliability and financial risks. Because our proposed EPS purposefully incorporates many design features that all but eliminate any potential adverse effect on system reliability (i.e. five year long-term commitments; 60% annualized capacity factor of underlying facilities that is intended to exclude shoulder or peaking plants but capture high-emitting baseload facilities; and upfront approval without ongoing monitoring in order to minimize any service disruptions caused by the eventual rejection of contracts found to be invalid) and overall costs to customers, <u>**any**</u> consideration for reliability or cost exemptions to the EPS must come with a heavy burden of proof on the LSE and a public process for consideration of the granting of the exemption.

<u>**Compliance & Enforcement Alternatives**</u>

We support the Staff Paper's assertion that the EPS not include a minimum size threshold (p. 17). SB 1368's direction that "**any** baseload generation supplied under the long-term financial commitment" (Section 8341(a), emphasis added) must comply with the EPS supports the argument for not having a size threshold at all, or at least having a very small, truly *de minimis*, size threshold. If any size threshold is to be applied, it must be applied to the underlying facility, and not the size of a contract or amount of electricity delivered to the grid, and we recommend a size threshold for underlying facilities of 5 MW (the maximum size limit under the Self Generation Incentive Program) to help simplify implementation of the standard by eliminating from consideration the truly small resources.

CPUC Staff Recommendations for EPS Compliance

The Staff Paper states that "The CPUC staff's Final Workshop Report recommends a "gateway" standard for the IOUs, rejecting a standard that requires on-going monitoring. For the ESPs, it recommends self-certification." (p. 17) We disagree with the Staff Paper's characterization of the proposed ESP treatment by the CPUC. The CPUC staff proposal indicates that the CPUC will "develop a filing/review process for the ESPs that comports with their current reporting processes." (p. 41, CPUC Final Staff Workshop Report). This does not necessarily imply self-certification; the CPUC also "reserve[d] the right to require up front review of long-term commitments by ESPs subject to the EPS." (p. 41) An upfront approval process for ESPs (that is consistent with the ESPs' current reporting schedule) might still be adopted by the CPUC in its pending final decision. As we state elsewhere, we strongly support an upfront approval process for **all** LSEs, and will continue to do so in our participation in the CPUC proceeding and CEC rulemaking.

Desirable Compliance and Verification Attributes

Question 5.1

> *Are there additional attributes of a compliance mechanism that should be considered?*

We strongly support the desired attributes of a compliance mechanism put forward by the Staff Paper. The attribute "Administrative Ease" should also apply to the CEC's administration of compliance with the standard, not simply to the POUs' administration to comply with the EPS. Thus, we suggest that the following sentence be added to this attribute on page 18: "In addition, the compliance mechanism should minimize the CEC's administration to ensure compliance with the standard."

Compliance and Verification Alternatives

Question 5.2

> *Is this typology sufficient? Are there other approaches to compliance and verification that should be discussed?*

We do not have any other approaches to suggest at this time.

Self-Certification

Question 5.3

Are there potential problems with self-certification that are not considered above?

There are a multitude of potential problems with a self-certification compliance scheme. As the Staff Paper itself recognizes in its description of the CPUC's staff recommendation for ESPs' compliance with the standard, self-certification is "a less onerous standard" (p. 17). The most desirable form of self-certification out of the options presented on page 19 is "the filing of a certificate of compliance and any necessary desired supporting documentation with the Energy Commission prior to making a commitment that is subject to the EPS." However, self-certification, without oversight and upfront approval by the CEC, violates all of the Staff Paper's stated goals of a compliance mechanism: effectiveness, providing transparency, minimizing uncertainty, and administrative ease (as we have suggested is modified as discussed in Question 5.1). If self-certification is used, transparency in the determination of EPS compliance is not guaranteed, since the decision would be made by the POU alone, without oversight from the CEC. As the Staff Paper describes, self-certification raises questions about whether a commitment meets the standard, and exposes POU customers to the significant financial and reliability risks from which SB 1368 is designed to protect them. Furthermore, in the event that monitoring is required, and/or penalties assessed for noncompliance, the CEC's administrative burden would be greatly increased. Given these significant (and avoidable) problems, it is apparent that allowing self-certification would jeopardize the effectiveness of the standard.

Question 5.4

Are there existing models of self-certification from other industries that should be considered?

There are no existing models of self-certification that we are aware of that would adequately protect consumers from financial and reliability risks and be simple to administer.

Question 5.5

Even given self-certification, is there a need for a mechanism that audits compliance filings? If so, what auditing mechanism (e.g., data requests from Energy Commission staff, independent auditing) would be appropriate?

We urge the CEC to adopt an upfront compliance mechanism. However, if self-certification were to be allowed as a compliance mechanism, auditing would be absolutely necessary to ensure compliance with SB 1368.

Prior Review and Approval

Question 5.6

Should prior review and approval be required of all procurement that is subject to the standard?

Yes. We strongly support the CPUC's recommendation for upfront, gateway approval prior to "prior to finalizing contract or commitment to construct" (Section 8a of final CPUC staff proposal), and also urge the CEC to adopt an upfront approval compliance mechanism. This is the most administratively straightforward and effective way of truly protecting consumers from the reliability and financial risks posed by imprudent investments in GHG-intensive generation. Allowing any LSE to show compliance after the fact would not offer the same protection to its consumers, and could result in highly litigious disputes if an LSE does enter into a long-term financial commitment that violates the performance standard.

Question 5.7

> *How could prior review and approval be structured so as to minimize delays? How can it best be meshed with existing reporting to the Energy Commission by the POUs and the Energy Commission's decision-making processes?*

We strongly support minimizing delays in upfront compliance and approval, as well as minimizing administrative filings by the POUs. For instance, there could be a time restriction placed on CEC review. Filing schedules could be synchronized with existing POU reporting schedules to minimize the total number of times a POU would have to submit filings to the CEC throughout a year.

Performance Monitoring

Question 5.8

> *Does a preferred standard require performance monitoring for the purpose of assessing compliance for certain resources? What types of resources? What data might be needed to evaluate the compliance of these resources?*

It is unclear what Staff means by a "preferred standard." Our proposed preferred standard would require upfront review and approval by the CEC before a POU can enter into a new long-term financial commitment, and would not require performance monitoring. We strongly recommend against any performance monitoring in the compliance evaluation enforcement of the standard, and encourage the CEC to design the standard such that it is unnecessary. A one-time upfront approval of commitments is the most administratively simple way to enforce the standard. As the Staff Paper points out on page 21, performance monitoring simply imposes additional compliance costs on both the POUs and the CEC and is undesirable from both points of view.

Verification of Physical Resources

Question 5.9

> *Is self-certification a reasonable option for new construction, repowerings and purchases of existing facilities? If so, what if any actions on the part of the POU would constitute self-certification? Is there a (legal) need for a certificate filing?*

The Staff Paper is correct in asserting that the data for physical resources that would be subject to the EPS can be relatively easily obtained. However, this does not provide an argument for self-verification by the POUs. This simply means that it will be easier for the POUs to demonstrate compliance with the EPS for these facilities. SB 1368 gives the CEC EPS enforcement authority over the POUs and is tasked with "ensur[ing] compliance" (Section 8341(c)(2)); the POUs should still submit their documentation to the CEC for prior review and approval.

Question 5.10

If there are multiple sources of data that can establish eligibility under the standard, should the Energy Commission specify which data are required or preferred?

We recommend that the CEC provide as much guidance as possible as to the type of documentation that would be sufficient to demonstrate compliance with the EPS, but we see no need to specify the exact documentation required. Third-party data should always be identified as the preferable form of data.

Question 5.11

Are there specific circumstances under which self-certification may not be an appropriate compliance mechanism for these resources? Are there instances when there may not be sufficient data filed with the Energy Commission or local permitting authorities, or otherwise available so as to allow for self-certification? For example, can filings with AQMDs misleadingly indicate that (a) the facility should be subjected to the EPS screen when it actually shouldn't, or (b) fails to meet the pass the EPS screen when it actually does so? If so, are there other data to support self-certification or would a review mechanism be necessary?

No; Self-certification should not be allowed under any circumstance. As we emphasize elsewhere in our comments (see response to 5.13), we would support the use of a list of pre-approved facilities that meet the EPS, rather than POU self-certification, even if there exist sufficient data to expeditiously determine EPS compliance. Though the difference between these two compliance mechanisms may at first seem trivial, the distinction is in fact significant. A pre-approved list, similar to the CEC-maintained list of RPS-eligible resources, would enable the Energy Commission to verify compliance *before* the POU makes a financial commitment to the generating unit(s) in question. Under an ex-post compliance system of self-certification, the Energy Commission would not have the opportunity to verify compliance until it is effectively too late. Only the former mechanism provides full assurance that POUs will not make imprudent commitments to high-emitting sources of electricity in violation of the EPS.

Unit-Contingent Contracts

Question 5.12

Is self-certification sufficient for unit-contingent contracts where historical emissions data is readily available? If not, what financial or performance data should be submitted as part of the compliance and verification process?

No. The compliance status of unit-contingent contracts should be relatively simple to determine, although this does not argue for self-certification by the POUs. As we assert elsewhere, self-certification presents several problems that can be easily avoided by requiring upfront compliance. However, we would support the use of a list of pre-approved and non-compliant facilities (see our answer to Question 5.13) in lieu of self-certification to verify compliance on an upfront basis. If a facility is not listed as an approved facility, the POU must demonstrate compliance with the EPS by supplying other data.

Question 5.13

Should the Energy Commission maintain a list of existing facilities that meet the EPS for the purpose of determining the eligibility of resources? Should the list also include those facilities that do not meet the EPS given available data?

A list of pre-approved and non-compliant facilities could possibly aid the administrative ease of compliance with the EPS. However, this approach obviously will only work for existing facilities, and new facilities will have to be demonstrated to be in compliance. Maintaining two lists (compliant and non-compliant) would be useful so that it is known which facilities were evaluated, and which facilities are known to not be in compliance with SB 1368 (versus simply not evaluated). Any facility not on those two lists would need to be shown in compliance in order for an LSE to invest in it.

However, the ongoing maintenance of these lists could be a potentially highly administratively-intensive task for the CEC, especially to track ongoing investments in existing facilities that may change the compliance status of a facility.

Question 5.14

If data is unavailable, e.g., a contract is signed with an existing unlisted unit whose thermal load is unknown, how should a determination be made?

If the thermal load of a cogeneration facility is unknown, the emissions of the facility should be calculated "as is" and not given a credit for the thermal load. Compliance with the standard should not be made on generic assumptions, without knowing how much thermal load is generated and then used by the facility.

Question 5.15

If a facility is undergoing/has undergone modifications (to allow it to meet an emissions standard), and if publicly available data does not show how modifications will change historical emissions sufficiently to meet the EPS, how should a determination be made?

POUs should be required to submit their own documentation for any modifications that allow facilities to meet the EPS but lack publicly available data, and this documentation should reviewed on a case-by-case basis by the CEC. As a non-market participant, the CEC should have access to privileged information concerning the expected performance of the modified facilities and does not need to limit its evaluation of compliance of a facility to publicly-available data. In the absence of any engineering estimates (though we do not see why these could not be obtained to illustrate compliance) of expected emissions performance (public or confidential), the CEC can rely on historical data from other facilities with similar technologies and the same fuel type to verify EPS compliance.

System Power
Question 5.16

> *If the emissions content of system power is based on geographic considerations, what information could be used to assign energy from unspecified sources to a geographic region? How could this information be reported or verified?*

The assignment of an emissions rate for unspecified power is a somewhat arbitrary process, and will never truly represent the emissions of the actual underlying resources. Given the inherent limitations of such an exercise, it is essential to also consider the consequences of whichever emissions rate the Commission determines appropriate. It is almost certain that these binary consequences would create very different incentives. If the Commission decides to assign an emissions rate to unspecified power that would enable all unspecified contracts to automatically pass the EPS, this would create the perverse incentive for LSEs to simply not specify the resources with which they contract, as this could allow LSEs to obscure any commitments to resources that would not pass the EPS if they were identified. In this case, we are extremely concerned that this significant loophole will expose California customers to significant reliability and financial risks. On the other hand, assigning an emissions rate to unspecified resources that would *not* pass the EPS would provide the positive incentive to improve emissions accounting and reporting throughout the system, and to develop a more robust estimate of emissions from sources that cannot be specifically identified (which will be needed down the road in any case under a GHG cap system). Thus, we recommend that the CEC deem that unspecified resources and system power do not meet the EPS.

We have concerns about assigning emissions values for system power based on geographic considerations (especially if there is no way to know for certain the geographic origin of system power), as this may expose SB 1368 to legal concerns regarding the violation of the Commerce Clause.

Contingent Contracts with Portfolio Owners
Question 5.17

> *How should the compliance of such contracts be assessed? If contracts which provide unspecified power are deemed non-compliant, should inclusion of a clause in the contract which limits the share of energy that may come from unspecified or ineligible sources qualify the contract for treatment as unit-contingent?*

SB1368 is clear that the standard should apply to all underlying baseload generation facilities. If the contract requires that the energy come from a given set of resources, each individual resource must meet the EPS. If a contract is unclear about which facilities supplies the electricity provided under the contract, the contract should be treated as unspecified power. All unspecified power resources should be treated uniformly, without any exemptions for limited shares of unspecified or ineligible resources. Each baseload resource supplied under every new financial commitment must meet the standard to comply with the statute (if there is a resource with an average capacity factor of less than 60%, then the EPS does not apply to it). If contracts which provide unspecified power are deemed non-compliant (which we recommend, in order to avoid creating an incentive to hide high-emitting resources that would not meet the standard), this provision should be universally applied to all unspecified power.

Question 5.18

> *Are there mechanisms that can be effectively used as part of a compliance and verification process to demonstrate that a seller is providing energy solely or primarily from eligible powerplants, even if the contract does not specifically require that he do so?*

The only way in which it can be certain that a seller is providing energy solely (primarily is not sufficient, since every underlying baseload facility must meet the standard to be compliant with SB 1368), is for this to be specifically required in the contract terms.

Blended Contracts

Question 5.19

> *Is self-certification a suitable compliance mechanism for all blended contracts? If not, what types of blended contracts might require another mechanism?*

As a general principle, NRDC/UCS believe that self-certification is an unacceptable compliance mechanism, due to the significant risks presented by after-the-fact enforcement. In addition, blending of emission rates should not be allowed in any circumstance, since SB 1368 is clearly intended to apply to all underlying baseload gernation. Thus, each individual resource behind a blended contract must meet the EPS. Unless the firming generators in a blended contract are specifically identified *and* are either non-baseload units or are contained in the Energy Commission's list of pre-approved facilities meeting the EPS (should the Energy Commission adopt this approach), the blended contract should be subject to ex-ante gateway review and approval by the CEC.

The Staff Paper notes that a blended contract that is firmed with unspecified power that does not meet the EPS may still qualify if the unspecified power has a "daily peaking profile." (p. 26) This application of the capacity factor to the contract is inconsistent with SB 1368, which is clear that the 60% capacity factor threshold is intended to be applied to each powerplant and underlying facility. In addition, the paper appears to assume that if the unspecified firming component of the blended product has a daily peaking profile, the firming will be provided by non-baseload peaking units. This assumption, however, may not prove true in regions or systems that are heavily reliant on coal or where coal-fired units are on the margin during peak periods. Thus, such blended contracts should not be automatically deemed compliant; the unspecified resource portion of a contract should be treated as a "resource" that like every other resource supplying a contract must individually meet the EPS. Any utility seeking approval for a blended contract in which the unspecified firming component does not qualify for the EPS must provide convincing evidence that the firming is indeed provided by solely by natural gas, hydro, or other peaking resources or resources that qualify under the EPS.

Question 5.20

Is it necessary or desirable to specify a minimum "renewable share" of blended contracts that include system power?

No. Utilities must not under any circumstances be allowed to circumvent the EPS through emissions blending, which is not consistent with SB 1368. In order to be consistent with SB 1368, each baseload facility supplying a contract must individually meet the EPS. The system power portion should be treated as a "facility" that must meet the EPS for the entire contract to meet the EPS, and as we describe in our response to Question 5.16, we strongly recommend that the CEC deem that system power does not meet the EPS.

Question 5.21

What information might be necessary to verify the eligibility of a blended contract and how can it be secured/provided?

The same information necessary to verify the eligibility of a standard power contract should be used to verify blended contract compliance. Again, in order to be consistent with SB 1368, each baseload facility underlying the contract must individually meet the EPS for the entire contract to comply with the standard.

Multiple Contracts

Question 5.22

What should the Energy Commission's position be on this issue relative to POU procurement practices? Are regulatory provisions needed to prevent back-to-back contracts for the same resource of less than five years? Are there circumstances under which such contracts are justified? If so, how should a determination be made?

The Energy Commission should expressly prohibit POUs from enrolling in back-to-back contracts for the same resource of less than five years. Such back-to-back contracts are never justified under SB 1368 compliance, and the CPUC rightly characterized this practice as contractual "gaming," which clearly subverts the intent, if not the precise letter, of SB 1368.

Because POU procurement is not subject to the same review process that applies to IOU procurement, the CEC will probably need to commit to some additional oversight to minimize the possibility of contractual gaming, not only through back-to-back contracts but also through temporal "slicing and dicing" of contracts. We expect that the additional reporting requirements that will be applied to all LSEs pursuant to AB 32 will facilitate CEC monitoring of contractual gaming.

Enforcement Options

Question 6.1

Is there agreement that an enforcement mechanism should be identified in the regulations?

Yes. Identifying an enforcement mechanism will provide certainty in how the EPS will be enforced. We strongly recommend the CEC adopt an upfront compliance and CEC verification/approval mechanism that would concentrate the CEC's enforcement of the EPS upfront, at the time the financial commitment is made.

Prior Review of Contracts

Question 6.2

Are there any other options for enforcement under this scenario?

We strongly support prior review and approval by the CEC of all new long-term financial commitments subject to the EPS, before the POU can enter into the long-term financial commitment. In the event that the POU defies a CEC determination that a new long-term financial commitment does not meet the EPS and enters into that commitment despite it not being approved by the CEC, some penalty mechanism should be applied.

Prior Review of "New Ownership Investments"

Question 6.3

Are there any other options for enforcement under this scenario?

See response to Question 6.2.

Review of Executed Contracts

Questions 6.4

Are penalties the right approach? If so, what types of penalties would be appropriate?

No. After-the-fact policing of contracts and any other financial commitments subject to SB 1368 would place a heavy administrative burden on Commission staff to continually monitor violations of compliance and assess penalties; as the Staff Report states, "Enforcement becomes more complicated if Energy Commission compliance review occurs after contracts have already been executed" (p. 28). Designing a system without upfront approval that instead relied on self-certification and after-the-fact penalties to enforce the standard would completely subvert the purpose of having a standard; if the standard is not met, assessing a penalty will not correct the failure to meet the standard, as the long-term commitment will already have been made. In addition, it is unlikely that a high enough penalty ("of sufficient weight," as the Staff Paper describes (p. 28)) can be set to effectively deter noncompliance; POUs could simply incorporate the penalties as a cost of doing business and the goals of SB 1368 would not be met, failing to protect Californians from significant financial and reliability risks associated with high-emitting resources.

We note that some sort of penalty and enforcement mechanism is still necessary for POUs that fail to bring contracts to the gate, or who modify the terms of the contracts after the CEC approves them. We do not suggest a particular penalty at this time, but note that it must serve as a sufficient deterrent to incentivize compliance with the Standard. The Staff Paper's suggestion of a penalty of "require[ing] any POU determined to have entered into a noncompliant contract to thereafter undergo prior review of all contracts" (p. 28) is by no means a sufficient penalty; this would only serve as a slap on the wrist and would completely fail to protect the POUs' customers from significant financial and reliability risks.

Although that we agree that "Once noncompliance is detected it should be quickly corrected and the POU brought back into compliance with SB 1368 and supporting regulations" (p. 28), we question how effectively the POU can be "brought back into compliance," since it would be difficult to renege on a signed contract, or unbuild a non-compliant powerplant. The idea that every contract should be required to contain a provision allowing for the automatic termination of a contract if it is found to be non-compliant by the CEC seems to be a prudent precaution, though the CEC should not rely on this as an enforcement mechanism and should rely on upfront approval of commitments as its primary form of enforcement of the standard.

Question 6.5

Are there any other approaches to quickly correct a noncompliant contract?

No.

Question 6.6

Does after-the-fact enforcement satisfy the Statute's goals of reducing California's exposure to costs associated with future regulation of greenhouse gases and "potential exposure of California consumers to future reliability problems in electricity supplies?"

No. See our response to Question 6.4. Once a financial commitment is made, it is extremely difficult to undo the commitment, and thus fails to protect California's consumers from significant financial and reliability risks.

Review of Completed "Investment" Transactions

Question 6.7

Are penalties an appropriate initial enforcement mechanism? If so, what types of penalties could serve as an effective deterrent under this scenario? Is it possible to fully correct an investment in a noncompliant facility after it has been made? If so, how?

No. See our response to Question 6.4. There is no way to un-build or un-invest in a powerplant once the non-compliant investment is made.

ATTACHMENTS
Comments submitted to the CPUC in Rulemaking 06-04-009

"Opening Comments and Legal Brief on Final Workshop Report and Staff Recommendations Regarding the Greenhouse Gas Emissions Performance Standard of the Natural Resources Defense Council (NRDC), The Utility Reform Network (TURN), the Union of Concerned Scientists (UCS), and the Western Resource Advocates (WRA)," October 18, 2006

"Reply Comments and Legal Brief on Final Workshop Report and Staff Recommendations Regarding the Greenhouse Gas Emissions Performance Standard of the Natural Resources Defense Council (NRDC), The Utility Reform Network (TURN), the Union of Concerned Scientists (UCS), and the Western Resource Advocates (WRA)," October 27, 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)

OPENING COMMENTS/LEGAL BRIEF ON FINAL WORKSHOP REPORT AND STAFF RECOMMENDATIONS REGARDING THE GREENHOUSE GAS EMISSIONS PERFORMANCE STANDARD OF THE NATURAL RESOURCES DEFENSE COUNCIL (NRDC), THE UTILITY REFORM NETWORK (TURN), THE UNION OF CONCERNED SCIENTISTS (UCS), AND THE WESTERN RESOURCE ADVOCATES (WRA)

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INTRODUCTION AND SUMMARY

The Natural Resources Defense Council (NRDC), The Utility Reform Network (TURN), the Union of Concerned Scientists (UCS), and Western Resource Advocates (WRA) respectfully submit these reply comments on the Final Workshop Report and Staff Recommendations in accordance with the "Assigned Commissioner's Ruling: Phase 1 Amended Scoping Memo and Request for Comments on Final Staff Recommendations" (ACR), dated October 5, 2006, and pursuant to Rules 1.9 and 1.10 of the California Public Utilities Commission's (CPUC or Commission) Rules of Practice and Procedure.

NRDC is a non-profit membership organization with a long-standing interest in minimizing the societal costs of the reliable energy services that a healthy California economy needs. In this proceeding, we focus on representing our more than 131,000 California members' interest in receiving affordable energy services and reducing the environmental impact of California's electricity consumption. TURN is a non-profit consumer advocacy organization which represents the interests of California's residential and small commercial customers. TURN has approximately 25,000 dues-paying members. UCS is a leading science-based non-profit working for a healthy environment and a safer world. Its Clean Energy Program examines the benefits and costs of the country's energy use and promotes energy solutions that are sustainable both environmentally and economically. WRA is a regional environmental law and policy center serving the Intermountain West States. Its Energy Program has been active before state public utility commission and other state and regional planning forums promoting clean energy investments for over 15 years.

We commend the Commission for the leadership role it has taken in establishing a greenhouse gas (GHG) emissions performance standard (EPS), which has now also been adopted into law on a statewide basis by Senate Bill (SB) 1368, signed by Governor Schwarzenegger on September 29, 2006. We strongly support the Commission's design and implementation of the EPS – an essential regulation that will protect Californians from the significant financial and reliability risks associated with additional investments in highly carbon-intensive generating technologies and help meet California's GHG reduction goals.

We commend the Commission staff for compiling a comprehensive report and support nearly all the recommendations made by staff. We believe the staff's Final Workshop Report and recommendations, issued on October 2, 2006, are largely consistent with SB 1368. Although we support most of the staff's changed recommendations from the draft workshop report, a few additional critical modifications and clarifications must be made to ensure the EPS is consistent with SB 1368 and accomplishes the Commission's goals. As directed by the ACR, these comments on the Final Workshop Report and staff recommendations presents a comprehensive summary of our final positions on the implementation and design details of the EPS.

We have organized our comments to follow the final staff proposal outline presented on pages 43-46 of the final workshop report, and in some places have incorporated by reference our previous comments in this proceeding. In summary, our comments elaborate on the following recommendations, which will ensure the EPS, as implemented by the CPUC, will be fully consistent with the statutory requirements of SB 1368:

- Except for modifications we suggest in these comments, we support the staff's final proposal for the EPS as being largely consistent with the requirements of SB 1368.

- SB 1368 in **no** way allows for **<u>any</u>** blending of resource emissions, and we urge the Commission to reject this staff recommendation for emissions blending for firmed renewables products.
- We strongly oppose any R&D exemption. If the Commission decides to allow for a case-by-case R&D exemption, we strongly urge the Commission to ensure that enough CO2 will be captured to meet the standard over the lifetime of the commitment.
- We strongly recommend that the Commission clarify the calculation of and specify a numerical value for the imputed emissions rate for unspecified power. We are willing to support using the CEC Net System Power emissions rates for this purpose, as long as the highest emissions rate is used for each fuel type.
- SB 1368 is clear in that the EPS criteria (annualized capacity factor and size threshold) should be applied to the underlying resource. The Commission should ensure that this principle is consistently applied throughout the standard, especially for partial-year contracts, self-generating facilities, and related contracts.
- We strongly recommend that the Commission **<u>not</u>** rely on after-the-fact monitoring provisions to identify most related contracts. This monitoring is largely unnecessary if the Commission adopts universal upfront review and application of EPS criteria to the underlying facility to be consistent with SB 1368.
- Any case-by-case reliability and/or cost exemption **<u>must</u>** come with a heavy burden of proof on the LSE and a public process for consideration of the granting of the exemption.
- We strongly recommend the Commission adopt a standard of 1,000 lbs CO2/MWh.
- We strongly urge the Commission to adopt an ESP compliance process that ensures upfront review of all long-term financial commitments.
- We recommend that the Commission make a one-time determination that RPS renewables are deemed compliant with the EPS.
- We strongly support the staff recommendation that utility retained generation that undergoes major renovations or is repowered be subject to the EPS.
- We support the “conversion” approach for an output-based methodology for calculating credit for cogeneration facilities. Credit should be awarded on a case-by-case basis for thermal energy that is actually used.
- We urge the Commission to adopt a size threshold for underlying facilities of 5 MW.

- We do not reiterate our comments on the legal issues associated with the EPS, other than to emphasize that the EPS is a prudent, reasonable, and constitutional exercise of the CPUC's Constitutional and statutory authority. We refer the Commission to our opening and reply legal briefs filed earlier in this proceeding for more detailed legal arguments.

DETAILED COMMENTS ON FINAL STAFF PROPOSAL

Design Goals for the EPS

As we have presented in our various pre-workshop comments, post-workshop comments, workshop report comments, and opening and reply legal briefs, we believe the most important design goals of the EPS are to protect Californians from the significant financial and reliability risks associated with additional investments in highly carbon-intensive generating technologies, to help meet the state's greenhouse gas (GHG) reduction goals. The updated staff proposal also includes these as top-priority goals, which are also supported by SB 1368 (Section 1 (i) and (j)). We also strongly support the goal of administrative simplicity. The proposal for the EPS that we offer in these comments will achieve these three primary goals.

Timeframe

We strongly support this aspect of the staff proposal. The Commission is on track to adopt a GHG performance standard by February 1, 2007, as directed by statute. We also recommend that the Commission coordinate as much as possible with the California Energy Commission (CEC) prior to adoption of the CPUC's standard, to ensure that a consistent statewide standard will be applied to *all* of the state's load-serving entities (LSEs) when the CEC adopts its GHG performance standard for publicly-owned utilities by June 30, 2007.

We support the staff proposal to implement the standard for an unspecified period of time and to reevaluate the standard "when an enforceable greenhouse gases emissions limit is established and in operation, that is applicable to load serving entities" (p. 43, Section 2)c)), which is consistent with the specific direction provided by SB 1368, Section 8341(g).

To Which LSEs does the EPS Apply?

We strongly support the Commission's determination in the ACR (p. 5) and the final workshop report that it has the legal ability and jurisdiction to apply a GHG performance standard on all the LSEs defined in SB 1368, including energy service providers (ESPs) and community choice aggregators (CCAs).

We strongly urge the Commission to adopt an ESP compliance process that ensures upfront *review of all long-term financial commitments.*

We strongly support the staff recommendation to "reserve the right to require up front review of long-term commitments by ESPs subject to the EPS" (p. 41). We believe the Commission *should* implement upfront review of ESPs' long-term commitments and has the authority to do so according to SB 1368. Although the Commission should consider adopting an ESP-specific process and could consider establishing a review and approval process for ESPs and CCAs that conforms with their existing reporting schedule (e.g., on a monthly or annual basis, consistent with their resource adequacy reporting schedule), it is imperative that this review and approval to determine compliance with the standard is done **<u>prior</u>** to contract execution by the ESPs. SB 1368, Section 8341(b)(2), specifically allows for Commission review of "any long-term financial commitment proposed *to be entered into* by an electric service provider or a community choice aggregator" (emphasis added). We also note that the final workshop report states that "all parties viewed a gateway screen approach as being the most effective approach if an EPS were to be implemented" (p. 19).

The standard **<u>must</u>** be enforced on an upfront basis for **<u>all</u>** LSEs, before any long-term commitments are made. Allowing after-the-fact review of some LSEs' long-term financial commitments would undermine the integrity of the GHG performance standard by opening up a significant loophole for noncompliance. See our Reply Comments on the Draft Workshop Report (September 15, 2006), p. 5.[4]

[4] "Reply Comments on Draft Workshop Report Regarding the Greenhouse Gas Emissions Performance Standard of the Natural Resources Defense Council (NRDC), The Utility Reform Network (TURN), the Union of Concerned Scientists (UCS), and the Western Resource Advocates (WRA)," September 15, 2006, p. 5.

We encourage the Commission to coordinate with the CEC prior to adoption of the CPUC's standard.

Although we agree with section 3)c) of the staff proposal that the Commission should not "delay pending program development for publicly-owned utilities," especially since the statutory deadlines for the CPUC and CEC are different, we encourage the Commission to coordinate closely with the CEC prior to adoption of the CPUC standard. (See our comments above in section II.2.)

We urge the Commission to allow opportunities for public comment on the filing/approval process for multi-jurisdictional utilities.

We support the staff proposal to develop a filing/approval process for multi-jurisdictional utilities (MJUs), and we encourage the Commission to allow opportunities for public comment on MJUs' proposals for alternative compliance as they are evaluated and implemented. We do not believe it is necessary or appropriate as part of this rulemaking for the Commission to identify the various possible proposals for MJUs' compliance with the EPS, except to specify that it must satisfy the SB 1368 criteria in Section 8341(d)(9). At this stage, we believe it would be sufficient for the Commission to adopt staff's recommendation on page 33 of the draft workshop report that a primary consideration in implementing the alternative compliance process for MJU's is that the "principal objectives of the EPS are met – especially, avoiding major new commitments that would tie California electric consumers to high-emission resources over the long-term."

Program Screens

We strongly support the staff proposal in applying the EPS on an upfront "gateway" basis, at the time an LSE's commitment is proposed, as this will greatly increase administrative simplicity and is the best way to truly ensure that consumers are protected from reliability and financial risk.

We recommend the Commission specify that "reasonably projected" emission rates and annualized capacity factors apply to the operation of a powerplant as it is "designed and intended" to run, as defined in SB 1368.

Section 4)b) of the staff proposal states that the standard will be applied to the "reasonably projected emission rate (lbs of CO2 per MWh) from the supply source over the term of the commitment." We recommend that the Commission change the language "reasonably projected," both in section 4)b), 4)c), and 5)c), to be consistent with SB 1368, which defines baseload generation (or the "covered resource" in the staff proposal) 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" (emphasis added). Thus, we recommend that the Commission replace the phrase "reasonably projected" in sections 4)b), 4)c), and 5)c) of the final staff proposal to "designed and intended."

We strongly support staff's recommendation to apply the EPS criteria to the underlying resources behind contracts with specified facilities, as this application of the standard is consistent with the direction of SB 1368. We urge the Commission to ensure that this principle is consistently applied throughout the standard's implementation.

We support the average annual capacity factor threshold of 60% for covered resources, as this is consistent with the definition of "baseload generation" provided by SB 1368 in Section 8340(a).

We strongly support the staff recommendation that "in the case of contracts, or other commitments with specified facilities, the annualized capacity factor of the underlying resource, rather than the size of the LSE commitment, should be used in determining whether the gateway screen applies" (p. 23). Accomplishing the EPS goal of minimizing the financial and reliability risk to billpayers of long-term commitments to high greenhouse gas emitting generation necessarily requires looking at the characteristics and emissions of the facility(ies) being contracted for, *not* the contract itself. After all, it is the generation facility that will incur the added costs and reliability issues if it is a high emitting resource, and all contracts will be affected by this, no matter their characteristics.

As the workshop report acknowledges and as we explain in our opening comments on the draft workshop report,[5] this application of the EPS to underlying facilities is fully consistent with the requirements of SB 1368:

> Section 8341 (b) (1): 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…*(emphasis added)*

Baseload generation is defined in Section 8340 (a) 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." And powerplant is defined in Section 8340 (m) as "a facility for the generation of electricity, and includes one or more generating units at the same location." Thus, the determination of whether the EPS applies to a resource should consistently be made based on the characteristics and greenhouse gas emissions of the powerplant, *not* on the contract.

Although we support staff's recommendation to apply the annualized 60% capacity factor criteria to underlying facilities, we also note that some of staff's other recommendations, in particular those that address treatment of partial contracts, self-generation facilities, and related contracts, are inconsistent with this principle. We urge the Commission to ensure consistency throughout the EPS by eliminating these contradictory applications of the EPS criteria. Specifically, as explained below in section II.5, we urge the Commission to modify the staff proposal so that partial contracts and self-generation facilities are both subject to the EPS, and to clarify that related contracts provisions are only necessary to a certain degree.

[5] "Opening Comments on Draft Workshop Report Regarding the Greenhouse Gas Emissions Performance Standard of the Natural Resources Defense Council (NRDC), The Utility Reform Network (TURN), the Union of Concerned Scientists (UCS), and the Western Resource Advocates (WRA)," September 8, 2006, p. 8-9.

Covered Power Sources

We strongly support the staff recommendation that utility retained generation that undergoes major renovations or is repowered be subject to the EPS.

We strongly support the staff recommendation to apply the EPS to all new LSE long-term financial commitments, including new utility-owned generation facilities, repowering and major renovations of utility retained generation (URG), and new and renewal contracts. Major renovations and repowering each fall under SB 1368's definition of a "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" (Section 8340(j), emphasis added). As long as the repowering or major renovation of a baseload URG is intended to extend plant life by five or more years, the investment should trigger the EPS. In particular, we support the staff's recommendation on page 24 of the final workshop report to apply the EPS to major renovations, which need not require expansion (or a net increase of the rated capacity of the plant):

> Major renovations of existing facilities, like other major financial commitments, involve long-term commitments that will affect power costs, environmental impacts, and ratepayer interests for many years. As the nation has learned with respect to "new source" standards under the Clean Air Act, extensive renovation does not necessarily require expansion, but it does implicate long-term emissions trends. Including such events in the definition of long-term commitments is reasonable and comports with the definition of baseload generation as defined in Section 8340(a).

The inclusion of major renovations to URGs as a "covered resource" to which the EPS is applied should be explicitly added to Section 5)a) of the staff proposal. We suggest that financial commitments to major renovations are defined by a dollar threshold.

We urge the Commission to ensure that partial-year contracts are not *exempted from compliance with the EPS.*

Staff's recommendation that "partial-year contracts for shaping resources that have less than a 60% annualized capacity factor not be covered by the EPS because of the seasonal reliability issues that they address" (p. 29) is in conflict with the principle of applying the EPS to the facilities underlying contracts, which is recommended elsewhere in the staff proposal and is also the intent of SB 1368 (see section II.4.b of these comments). Although we recognize that partial-year contracts can help address *short-term* reliability needs, we maintain that there is absolutely no need for such an exemption for partial-year contracts.

To be consistent with SB 1368 as described above, *all* long-term contracts should go to the gate to be evaluated against the standard, and the characteristics of the underlying facilities will determine if it must be subject to the EPS. If a partial-year contract is really intended to address *seasonal* reliability concerns, then the contract would probably be less than five years in length, and thus would not even go to the gate for consideration under the EPS. If the partial-year contract is longer than five years in duration, then it is a long-term financial commitment that should most certainly be subject to the EPS. In addition, if the Commission decides to adopt a case-by-case reliability exemption, the burden of proof should be on the LSE proposing such a contract to demonstrate the need for the partial-year contract for reliability needs, but there is no reason to exempt these partial-year contracts outright. Under staff's proposal, a long-term contract for a "summer product" (or any other seasonal contract providing energy for part of the year) from a specified pulverized coal plant could conceivably automatically pass the EPS, which would undermine the goal of limiting significant financial and reliability risks from high carbon-emitting resources. We urge the Commission to **not** specifically exempt partial-year contracts as the staff recommends and instead direct that these contracts must meet the EPS like any other long-term contract.

We urge the Commission to ensure that the EPS criteria applies to all *underlying facilities, including self-generation facilities.*

Staff's recommendation that the EPS apply only to electricity delivered to the grid by self-generating facilities is also inconsistent with applying the EPS to underlying facilities. Staff provides the following argument for its recommendation: "where the electrical output retained on-site by a customer is not part of the LSE's financial commitment or acquisition, we cannot conclude that it falls within either the commission's purposes in establishing the EPS, or the definition of covered resources in

AB [sic] 1368" (p. 30). To the contrary, Section 8341(b)(1) in SB 1368 specifically directs that:

> The commission shall not approve a long-term financial commitment by an electrical corporation unless **<u>any baseload generation</u>** <u>supplied under the long-term financial commitment</u> complies with the greenhouse gases emission performance standard…*(emphasis added)*

Application of the EPS criteria to the underlying facility, regardless of whether it is a self-generator, does not in any way represent an attempt to control the operations of the entire generating facility, as some parties have suggested in this proceeding. Rather, the EPS governs only the portion of electricity *contracted for* by a California LSE, although the criteria to determine whether or not the electricity contracted for meets the EPS (annualized capacity factor and emissions rate) should apply to the underlying facility. Thus, the emissions *rate* (lbs/MWh) of the underlying facility (if it has an annualized capacity of 60% or greater), including self-generating facilities, should be compared to the standard to see if any contract or other financial commitment passes the EPS. We strongly recommend that the Commission clarify that the EPS criteria should apply to the underlying facilities, and that this view should be held consistently across the various design aspects of the EPS. We urge the Commission to reject staff's recommendation to apply the EPS only to the amount of electricity delivered to the grid.

We urge the Commission to clarify that the EPS size criteria should also apply to the underlying facilities behind specified contracts instead of the size of the LSE commitment.

We again support the staff recommendation that "in the case of contracts, or other commitments with specified facilities, the annualized capacity factor of the underlying resource, *rather than the size of the LSE commitment*, should be used in determining whether the gateway screen applies" (p. 23, emphasis added). This sentiment expressed in the recommendation discussion in the Final Workshop Report conflicts with section 5)d)i) of the final staff proposal. Section 8341(b)(1) of SB 1368 is clear that the EPS should apply to "**<u>any</u>** baseload generation supplied under the long-term financial commitment" (emphasis added). We recommend that the Commission revise the staff proposal to ensure that the size threshold applies to the underlying facility and not the amount of electricity delivered to the grid or the contract size. (See our comments above in section II.4.b for additional discussion of the importance of applying the EPS criteria to the characteristics of the underlying facility.)

Thus, in order to be consistent with the requirements of SB1368, we recommend that all references (both in the staff proposal and the process flow chart on page 47) to the size threshold be modified to be clear that the it applies in all cases to the underlying facility, **not** only to the commitment or amount of electricity delivered to the grid.

Staff's recommendation to apply the size threshold to contracts and commitments is not only counter to the intent of SB 1368, but also fails to "mitigate administrative complexity" (p. 30), contrary to the staff report's claim. As explained below in section II.5.f, such application of the size threshold to commitment size introduces the need for after-the-fact monitoring of related small contracts, which in fact *increases* administrative complexity and is not consistent with existing Commission duty to eliminate the need for "after-the-fact reasonableness reviews" for specific long-term procurement transactions (Public Utilities Code § 454.5(d)(2)).

We urge the Commission to adopt a size threshold for underlying facilities of 5 MW.

Currently, the staff proposal suggests a size threshold of 25 MW. As we argue above, any size threshold should apply to the entire underlying facility instead of the amount of power under contract or delivered to the grid. Staff argues for "a 25 MW or greater threshold for contracts and commitments for the screening process in order to focus on long-term contracts, create consistency, and mitigate administrative complexity across the screening process" (p. 30). However, the direction of Section 8341(b)(1) of SB 1368 that the EPS apply to "**any** baseload generation supplied under the long-term financial commitment" (emphasis added) supports the argument for not having a size threshold at all, or at least having a very small, truly *de minimis*, size threshold.

Therefore, we do not support a 25 MW threshold and continue to recommend a size threshold for underlying facilities of 5 MW (the maximum size limit under the Self Generation Incentive Program) to help simplify implementation of the standard by eliminating from consideration the truly small resources. In addition, a size threshold should not be applied to any *contracts*, specified or unspecified.

> *We strongly recommend that the Commission* <u>*not*</u> *rely on after-the-fact monitoring provisions to identify most related contracts. This monitoring is largely unnecessary if the Commission adopts universal upfront review and application of EPS criteria to the underlying facility to be consistent with SB 1368.*

In sections 5)d)iii) and 7)f) of the staff proposal, the staff proposes a prohibition of "related contracts with the same supplier, likely resource, or known facility, or a series of related or similar contracts with separate sources" by considering them as a single contract to prevent "slicing and dicing" of large contacts into forms that would slide past the EPS. The staff proposes to enforce this requirement and assess a penalty to LSEs that do not disclose these contracts. Although we agree that slicing and dicing of contracts is a serious concern, we do not believe after-the-fact monitoring is consistent with statutory requirements, nor the most efficient way to handle this potential problem.

In order to be fully consistent with Section 8341(b)(1) of SB 1368, which requires the EPS to apply to "<u>**any**</u> baseload generation supplied under the long-term financial commitment" (emphasis added), the standard's size and capacity factor criteria should be applied to the underlying facility, rather than the LSE contract. This would eliminate the need for monitoring of slicing and dicing of contracts along two of the dimensions mentioned in the staff proposal: size and capacity factor. Slicing and dicing of contracts by time duration (e.g. signing back-to-back-to-back four-year contracts instead of a single 12-year contract) to evade the EPS requirements would still remain a concern, but this would reduce the scope of the concerns envisioned by staff.

In addition, after-the-fact monitoring conflicts with the requirements of Public Utilities Code § 454.5(d)(2), established by AB 57 (2002), which requires upfront approval for long-term procurement so as to eliminate the need for "after-the-fact reasonableness reviews" for specific transactions. After-the-fact policing of related contracts would place a heavy administrative burden on Commission staff to continually monitor the "slicing and dicing" of contracts and potentially assess penalties. It is unclear how this enforcement would take place, as related contracts could occur at different times, or multiple California LSEs could agree to team up for multiple small contracts, thus making the contracts impossible to track.

In addition, designing a system with penalties would subvert the purpose of having a standard; if the standard is not met, assessing a penalty will not correct the failure to meet the standard, as the long-term commitment will already have been made. A "professional rule of reasonableness" to determine related contracts is not sufficient to protect Californians from significant financial and reliability risks associated with high-emitting resources.

We strongly recommend that the Commission not adopt this related contract monitoring and penalty provision of the staff proposal, as it is rendered largely unnecessary if the Commission adopts universal upfront review and application of EPS criteria to the underlying facility or facilities as we recommend and as would be consistent with SB 1368. This is also consistent with the direction in SB 1368 as noted above. Temporal slicing-and-dicing of contracts still remains a concern, however, so reporting and monitoring of this type of related contracts would still be appropriate.

Applicability of the EPS to Qualifying Facilities.

For a full discussion of our view on the applicability of the EPS to Qualifying Facilities (QFs), please see p. 27-28 of NRDC's Opening Legal Brief filed on June 30, 2006.[6] In summary, we recommend that the Commission clarify that all financial commitments will be analyzed under the Standard, while allowing for a case-by-case review of otherwise exempt QF contracts to ensure that the Standard will not be used to prohibit a contract that is *currently* – that is, at the time of Commission review of a new long-term financial commitment – mandated under federal law. We emphasize the currency of the federal requirement because the mandatory purchase rules for QFs established by the Public Utility Regulatory Policy Act (PURPA) are in flux; the Energy Policy Act of 2005 (EPAct 2005) empowered FERC to remove mandatory purchase requirements upon IOU application, if FERC finds that the electricity market in which the IOU operates is sufficiently competitive. We anticipate that California's IOUs will be

[6] "Opening Brief on Phase 1 Legal Issues Associated with the Greenhouse Gas Emissions Performance Standard of the Natural Resources Defense Council (NRDC)," June 30, 2006.

relieved of their mandatory purchase obligations over the coming years as the provisions of EPAct 2005 are implemented by FERC. Thus, we suggest that the CPUC address the issue of mandatory QF contracts by including language similar to the following in its final decision on the EPS: “This standard shall not be construed in a manner that would require actions in conflict with federal law, including 16 U.S.C. § 824a-3 (2006).”

We support the “conversion” approach for an output-based methodology for calculating credit for cogeneration facilities. Credit should be awarded on a case-by-case basis for thermal energy that is actually used*.*

We support the “conversion” approach (rather than the “emissions avoided” approach) described in Attachment 2 of the ACR as the most appropriate output-based methodology (pounds of GHG emitted per MWh) calculation of the effective overall GHG emissions rates for cogeneration facilities – a calculation required by SB 1368. The “conversion” approach (crediting the used thermal load as its electric load equivalent) is more accurate than an “emissions avoided” approach (estimating the emissions that a boiler system would otherwise emit had it provided the same thermal output).

Cogeneration credit for the thermal energy generated and used by cogeneration (cogen) facilities should be applied to the *overall* emissions of the plants for the purpose of evaluating the long-term commitment made by an LSE for *any* part of the electricity output of the facility. This general calculation methodology should be used for all cogeneration facilities, but the credit should be reviewed and awarded on a case-by-case basis since cogeneration facilities are different, and the efficiency and use of the waste heat differs greatly from facility to facility.

Additionally, we repeat the assertion in NRDC’s pre-workshop comments[7] that the use of the 3,412 Btu/kWh conversion factor for an output-based approach is appropriate, as it is a commonly-accepted engineering conversion factor and is consistent with the distributed generation standards established by the California Air Resources Board (CARB) in SB 1298 (2000).

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[7] “Phase 1 Pre-Workshop Comments on the Greenhouse Gas Emissions Performance Standard of the Natural Resources Defense Council (NRDC),” June 12, 2006, p. 14.

We suggest the use of the following formula, which is similar to the Energy Producers and Users Coalition and Cogeneration Association of California (EPUC/CAC) proposed methodology:

$$EmissionRate = \frac{TotalEmissions}{kWh_{electricity} + \frac{kWh}{3412Btu}\left(Btu_{used\_output}\right)}$$

The *TotalEmissions* should be calculated using the designed and intended carbon intensity of the fuel and turbine characteristics or could be measured at the plant for existing facilities. The $kWh_{electricity}$ delivered is the electrical output at the plant in normal operating conditions.

The Btu_{used_output} value is the heat ***used*** onsite in processes or heating and should be estimated from plant/process/building designs; the heating load being met by the cogen facility and the heat supplied to local processes by the cogen plant should be known by the design engineers. Waste heat and unused useable heat should not be included in the Btu_{used_output} value. This value should be calculated on a case-by-case basis, and should not be a universally assumed "fraction of the heat that is actually used by the thermal host," as suggested on page 2 of Attachment 2. This is the major clarification/difference between our proposed approach and the EPUC/CAC approach; the Btu value used for the thermal energy in our proposal represents *used* heat, not available heat. If there is more usable heat available than heat needed and used, only the heat that is actually used should be included in the calculation.

It is important to note that the conversion factor in an output based approach used to credit used thermal load must be the 3412 Btu/kWh and *not* the heat rate of the generator. Using the heat rate of the generator is not appropriate in this context as it reflects electric generation efficiency and is not a conversion factor. Because this is an output-based approach, and because total emissions reflect all the fuel burned regardless of conversion efficiencies, using heat rates for converting used heat to kWh would double count the efficiency losses.

The "conversion" approach has the advantage of being more accurate in calculating the actual emissions rate of the cogen facility, since it takes into account the actual thermal output that is used, which is information that should be available from design engineers. The "emissions avoided" approach inherently requires more detailed estimates, especially if the facility is new.

We recommend that the Commission make a one-time determination that RPS renewables are deemed compliant with the EPS.

The final workshop report recommends that all renewables that meet the EPS screening criteria "should appear at the gate and file their applicable net emissions rate" (p. 36). We instead recommend that the Commission make a one-time stipulation at this time, based on the evidence presented by the Green Power Institute in their post-workshop comments filed on July 27, 2006, that all renewables are deemed in compliance with the EPS. Thus, renewables will still go to the gate, but will automatically be deemed in compliance with the EPS, and thus pass the standard. This approach is consistent with SB 1368, Section 8341(d)(4), which simply requires the Commission to "consider" net emissions. This one-time consideration and showing of deemed compliance for renewables will increase administrative simplicity by eliminating the need for each renewable resource to individually demonstrate an emissions rate lower than the EPS.

We also support the staff's distinction between deemed compliance and an exemption; although this may seem like a minor nuance, this distinction should continue to be made in order to accurately represent the treatment of renewables in the EPS – namely, that they meet the standard and are not true exemptions to the rule.

Reliability and overall cost considerations have already been accounted for in the design of the EPS. Any case-by-case reliability and/or cost exemption must come with a heavy burden of proof on the LSE and a public process for consideration of the granting of the exemption.

SB 1368 does not specifically call for exemptions for reliability and cost considerations. Section 8341(d)(6) stipulates: "In *adopting and implementing* the greenhouse gases emission performance standard, the commission…shall consider the effects of the standard on system reliability and overall costs to electricity customers" (emphasis added). We are committed, along with the Commission, to maintaining and enhancing the reliability of California's electricity grid. We also consider two of the primary purposes of the EPS to be protecting Californians against long-term reliability and financial risks. Therefore, we do not believe that a reliability or cost exemption for the EPS is necessary because the standard itself is designed as protection from these risks.

Short-term reliability is not affected by the EPS, since the standard applies only to long-term contracts of over five years and does not address economic dispatch issues. Peaking or shoulder plants (which have an annual average capacity factor of less than 60 percent) that are needed for reliability purposes are not subject to the EPS. In addition, the EPS only determines *which* baseload plants can be included in new long-term commitments, not *whether* they can run and provide power in the short term. If a plant is intended to run at a 60% or greater capacity factor, then it *should* be required to meet the EPS, since it could potentially present long-term reliability and financial risks.

We believe that our proposed modifications to the staff workshop report will ensure that the EPS is designed specifically to avoid reliability and overall cost concerns, as well as to protect Californians from long-term reliability and financial risks. Because our proposed EPS purposefully incorporates many design features (five year long-term commitments; 60% annualized capacity factor of underlying facilities that is intended to exclude shoulder or peaking plants but capture high-emitting baseload facilities; and upfront approval without ongoing monitoring in order to minimize any service disruptions caused by the eventual rejection of contracts found to be invalid) that all but eliminate any potential adverse effect on system reliability and overall (including long-term) costs to customers, <u>any</u> consideration for reliability or cost exemptions to the EPS should come with a heavy burden of proof on the LSE and a public process for consideration of the granting of the exemption.

What is the Standard and How Determined?

We strongly recommend the Commission adopt a standard of 1,000 lbs CO2/MWh.

We support section 6)a)i) of the staff proposal, which institutes a single standard for all covered facilities. We also support the staff proposal that this emissions standard be set at a level that is "based upon based upon CCGT performance of a powerplant that is designed and intended to provide electricity generation at an annualized plant capacity factor of at least 60 percent," consistent with the SB 1368 definition of baseload generation in Section 8340(a).

We continue to recommend a standard of 1,000 lbs CO2/MWh. We disagree with the staff report that "[t]he majority of parties commenting on the Revised Staff Report's recommendation of 1,000 lbs CO2/MWh were opposed" (p. 34). By our count, most parties who specifically commented on a numerical emissions rate at which to set the EPS supported a value of 1,000 lbs CO_2 per MWh. Given that SB 1368 already deems all existing CCGTs to be in compliance, we do not see a need, based on the data presented in this proceeding, to set the EPS level higher than 1,000 lbs CO_2/MWh in order to accommodate existing CCGTs. For a full discussion, please see our Opening and Reply Comments on the Draft Workshop Report.[8,9]

We strongly oppose any R&D exemption. If the Commission decides to allow for a case-by-case R&D exemption, we strongly urge the Commission to ensure that enough CO2 will be captured to meet the standard over the lifetime of the commitment.

While SB 1368 determines that "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" (Section 8341(d)(5)), the statute in no way calls for an R&D exemption. This section of SB 1368 simply details how sequestered GHG emissions are factored into the calculations of a facility's emissions rate in order to determine compliance, not to exempt any facility.

We strongly oppose any R&D exemption, even on a case-by-case basis, as recommended by the staff proposal. (Please refer to our comments on this issue in our

[8] "Opening Comments on Draft Workshop Report Regarding the Greenhouse Gas Emissions Performance Standard of the Natural Resources Defense Council (NRDC), The Utility Reform Network (TURN), the Union of Concerned Scientists (UCS), and the Western Resource Advocates (WRA)," September 8, 2006, p. 13-14.

[9] "Reply Comments on Draft Workshop Report Regarding the Greenhouse Gas Emissions Performance Standard of the Natural Resources Defense Council (NRDC), The Utility Reform Network (TURN), the Union of Concerned Scientists (UCS), and the Western Resource Advocates (WRA)," September 15, 2006, p. 5-6.

Reply Comments on the Draft Workshop Report.[10]) Because the Commission has selected a gateway standard, which we agree with, the mere "assurance" that an IGCC coal plant that "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 in fact realize such a plan and reduce and maintain emissions at or below the EPS limit in the future. Though we believe that the Commission should support research, development, and deployment of advanced technologies, it must not do so at the expense of potentially undermining the EPS and exposing Californians to significant reliability and financial risks.

If the Commission wants to allow some limited flexibility for demonstration of advanced coal technologies, we strongly urge the Commission to demand specific, and enforceable, assurance from the LSE proposing the commitment to that facility that enough CO2 will be captured and sequestered to meet the standard over the lifetime of the commitment.

We note that there are currently two examples of plants that plan to sequester carbon dioxide from day one of the plants' operation: British Petroleum and Edison Mission Group's Carson Hydrogen Power Project (petroleum coke IGCC with the CO2 to be captured and used for enhanced oil recovery) planned for Carson, CA[11] and an IGCC coal plant that will capture its CO2 emissions proposed by Xcel Energy to be built in Colorado.[12] Their existence raises the question as to why an R&D exemption would be necessary to avoid compliance with the EPS.

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[10] "Reply Comments on Draft Workshop Report Regarding the Greenhouse Gas Emissions Performance Standard of the Natural Resources Defense Council (NRDC), The Utility Reform Network (TURN), the Union of Concerned Scientists (UCS), and the Western Resource Advocates (WRA)," September 15, 2006, p. 11.

[11] See http://www.bpalternativenergy.com/liveassets/bp_internet/alternativenergy/next_generation_hydrogen_carson.html.

[12] See http://www.denverpost.com/ci_4187912?source=rss.

Application of the Standard to Units and Contracts

> *SB 1368 in no way allows for <u>any</u> blending of resource emissions, and we urge the Commission to reject this staff recommendation for emissions blending for firmed renewables products.*

The staff proposal recommends emissions blending of the resources in a firmed baseload renewable contract. The staff's application of the "baseload" criteria (60% annualized capacity factor) to the firmed renewable product (essentially a multi-unit contract) runs counter to SB 1368's intention that the EPS should be applied to "<u>**any**</u> baseload generation supplied under the long-term financial commitment" (Section 8341(b)(1), emphasis added). In addition, this contradicts the staff proposal recommendation that "each covered unit must qualify" in multi-unit contracts (Section 7)b)). The statutory guidance provided by SB 1368 is clear that the standard is to be applied to the underlying facilities behind a contract, not a blend of their emissions.

Emissions blending should never be allowed, as it would open a significant loophole that would completely compromise the integrity of the standard. We are extremely concerned that this provision will allow high-emitting resources that would never pass the standard alone (such as pulverized coal) to be blended with zero-emitting renewable resources. By allowing the emissions of a high-carbon emitting resource to be "diluted" by a cleaner resource, emissions blending would circumvent the ability of the EPS to reduce significant reliability and financial risks associated with high carbon-emitting resources. Although this sort of tradeoff between high- and low-emitting resources may be appropriate in the GHG cap system to be implemented in California under AB 32, there is no place for emissions blending in the EPS.

For a full discussion on this emissions blending topic, please see our Opening Comments on the Draft Workshop Report.[13]

[13] Opening Comments on Draft Workshop Report Regarding the Greenhouse Gas Emissions Performance Standard of the Natural Resources Defense Council (NRDC), The Utility Reform Network (TURN), the Union of Concerned Scientists (UCS), and the Western Resource Advocates (WRA)," September 8, 2006, p. 14-16.

We strongly recommend that the Commission clarify the calculation of and specify a numerical value for the imputed emissions rate for unspecified power. We are willing to support using the CEC Net System Power emissions rates for this purpose, as long as the highest emissions rate is used for each fuel type.

The staff proposal recommends applying the "most current CEC 'Net System Power' [NSP] average at time of new or renewed commitment" (Section 7)e)) to contracts for unspecified power. The staff proposal, however, does not specify the numerical emissions rate associated with the NSP. We recommend that the Commission adopt a specific numerical imputed emissions rate for unspecified resources, so as to provide certainty about what this emissions rate will be in relation to the standard.

The pitfall of relying on the CEC Net System Power average is that an averaged emissions rate provides no information or guidance on the critical distinctions between emissions from different types of generating units. Averaging lower and higher emitting sources invariably dilutes the emissions rates of the higher emitting sources, and provides a significant loophole for long-term unspecified resource contracts. NRDC appreciates Staff's willingness to "monitor contracting patterns and behaviors to ensure they do not change for this reason," (p. 38), but we believe this monitoring activity would increase the administrative burden posed by the EPS, and is contrary to staff's own stated goal of administrative simplicity and upfront compliance.

The assignment of an emissions rate for unspecified power is a somewhat arbitrary process, and will never truly represent the emissions of the actual underlying resources. Given the inherent limitations of such an exercise, it is essential to also consider the consequences of whichever emissions rate the Commission determines appropriate. It is almost certain that these binary consequences would create very different incentives. If the Commission decides to assign an emissions rate to unspecified power that would enable all unspecified contracts to automatically pass the EPS, this would create the perverse incentive for LSEs to simply not specify the resources with which they contract, as this could allow LSEs to obscure any commitments to resources that would not pass the EPS if they were identified. In this case, we are extremely concerned that this significant loophole will expose California customers to significant reliability and financial risks. On the other hand, assigning an emissions rate to unspecified resources that would *not* pass the EPS would provide the positive incentive to improve emissions accounting and reporting throughout the system, and to develop a more robust estimate of emissions from sources that cannot be specifically identified (which will be needed down the road in any case under a GHG cap system).

Because we understand from the workshop in June that no LSE is planning to procure any new long-term contracts for system power, we see no reason for the CPUC to create a significant new loophole in the EPS by imputing an emissions rate for unspecified power that would pass the standard.

For any resource mix assumption (be it the CEC NSP or another methodology), one would still need to assign emissions rates for each kind of fuel, and emissions rates within even one kind of fuel can vary substantially based on the technology used. Since we have no way of knowing exactly which technology is used for each of the fuel types in a resource mix, we recommend assigning the highest emissions rate for each fuel type, as provided in the data response to data request #3 in this proceeding (using the workbook entitled "Representative Heat Rates and Emissions for various technologies"). We note that the heat rates provided in this spreadsheet, from which the representative emission rates are calculated, are full load heat rates. 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 (as plant output decreases, the corresponding heat rate increases, and since emissions are proportional to heat rate for the same fuel type, the emissions rate increases as well). Thus, it would be most realistic to use the highest representative heat rates in calculating emissions for unspecified power.

We are willing to support the staff recommendation of using the CEC NSP, if the highest emissions rate for each fuel type is used to calculate the overall weighted emissions rate. For example, using the current 2005 NSP (38.5% coal, 23.5% large hydroelectric, 33.3% natural gas, 0% nuclear, and 4.7% eligible renewables), and the high end emissions rates as provided in data request #3 (2,560 lbs CO_2/MWh for coal, 2,050 lbs CO_2/MWh for natural gas, and assuming a zero emissions rate for hydro, nuclear, and renewables), the weighted emissions rate would be 1,668 lbs CO_2/MWh.

Monitoring and Enforcement

We strongly support gateway, upfront review for the EPS, with "approval required prior to finalizing contract or commitment to construct" (section 8a), for **all** LSEs, without any form of ongoing enforcement. Although staff does not have a specific recommendation at this time for what sources of documentation should be required, we support their recommendation to use "independently verified emissions data" (p. 42). We also recommend that the Commission add to the list of suggested sources of information the sources listed in SB 1368, Section 8341(b)(4):

> 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, as determined by the commission based upon the electricity purchase contract, any certification received from the Energy Commission, any other permit or certificate necessary for the operation of the powerplant, including a certificate of public convenience and necessity, any procurement approval decision for the load-serving entity, and any other matter the commission determines is relevant under the circumstances.

We urge the Commission to ensure that documentation of EPS compliance allows for an "apples-to-apples" comparison of emissions rates.

We also emphasize that documentation of compliance with the EPS must allow for an "apples-to-apples" comparison of emissions rates of covered resources with the EPS. This is most appropriately accomplished through the use of designed and intended heat rates, not full load heat rates. (See our Reply Comments on Draft Workshop Report, p. 6-7 for a full discussion.[14]) We suggest that the Commission clarify the staff's recommendation to use "average heat rate" (p.23) as the "designed and intended" heat rate for documentation purposes.

[14] "Reply Comments on Draft Workshop Report Regarding the Greenhouse Gas Emissions Performance Standard of the Natural Resources Defense Council (NRDC), The Utility Reform Network (TURN), the Union of Concerned Scientists (UCS), and the Western Resource Advocates (WRA)," September 15, 2006, p. 6-7.

Offsets, Safety Valves, and Other Flexibility Devices

We strongly support staff's proposal for no offsets or market price safety valves. In addition to requiring "significant up front analysis and ongoing monitoring" (p. 39), these flexibility devices would subvert the purpose of the EPS by providing a way to circumvent its requirements.

Section 9b of the staff proposal calls for a case-by-case reliability and cost exemption; please refer to our comments above in section II.5.j on the same issue. Any reliability or cost exemption should also carry with it a heavy burden of proof on the LSE and a public process for consideration of the granting of the exemption.

<u>COMMENTS ON LEGAL ISSUES</u>

Our positions on the legal issues associated with the GHG performance standard have not changed. We continue to strongly assert that EPS is a prudent, reasonable, and constitutional exercise of the CPUC's Constitutional and statutory authority. SB 1368 provides additional authority and jurisdiction to implement the EPS, but does not change our prior legal conclusions. We refer the Commission to NRDC's Opening Legal Brief for a full discussion of the following legal issues associated with implementation of the standard:[15]

- The CPUC has ample authority to implement the standard. (p. 8-19)
- The standard does not in any way violate the Commerce Clause. (p. 19-26)
- PURPA issues and QF status. (p. 27-28)
- The foreign policy argument raised by some parties is spurious. (p. 28-30)

In addition, as directed by the ACR, NRDC intends to submit a reply on November 1, 2006 to address the supplementary material on Commerce Clause issues presented by the Center for Energy and Economic Development (CEED) in their September 8, 2006 comments on the draft workshop report. In summary, however, the CEED supplemental material simply rehashes the legal issues that have already been

[15] "Opening Brief on Phase 1 Legal Issues Associated with the Greenhouse Gas Emissions Performance Standard of the Natural Resources Defense Council (NRDC)," June 30, 2006.

thoroughly rebutted by NRDC and other parties in the previous round of opening and reply Legal Briefs submitted in this proceeding.[16]

CONCLUSION

We commend the Commission for proactively seeking to establish a GHG performance standard that can be easily and quickly implemented. The standard is critically needed to protect Californians from the significant financial and reliability risks associated with new investments in highly carbon-intensive generating technologies and to help meet California's GHG reduction goals. We support the staff's final proposal for the EPS as being largely consistent with the requirements of SB 1368, and urge the Commission to adopt the modifications we suggest in these comments to make the EPS fully consistent with SB 1368. We also encourage the Commission to continue to work closely with the CEC and to also consult with the California Air Resources Board, as is consistent with the direction in SB 1368. We appreciate the thoughtful questions presented by the Division of Strategic Planning staff to guide parties' comments throughout the workshop and comment process. We continue to look forward to further developing and finalizing the details of the EPS with the Commission and other parties.

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[16] "Reply Brief on Phase 1 Legal Issues Associated with the Greenhouse Gas Emissions Performance Standard of the Natural Resources Defense Council (NRDC)," July 11, 2006.

Dated: October 18, 2006

Respectfully submitted,

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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)

REPLY COMMENTS/LEGAL BRIEF ON FINAL WORKSHOP REPORT AND STAFF RECOMMENDATIONS REGARDING THE GREENHOUSE GAS EMISSIONS PERFORMANCE STANDARD OF THE NATURAL RESOURCES DEFENSE COUNCIL (NRDC), THE UTILITY REFORM NETWORK (TURN), THE UNION OF CONCERNED SCIENTISTS (UCS), AND THE WESTERN RESOURCE ADVOCATES (WRA)

October 27, 2006

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INTRODUCTION AND SUMMARY

The Natural Resources Defense Council (NRDC), The Utility Reform Network (TURN), the Union of Concerned Scientists (UCS), and Western Resource Advocates (WRA) respectfully submit these reply comments on the Final Workshop Report and Staff Recommendations in accordance with the "Assigned Commissioner's Ruling: Phase 1 Amended Scoping Memo and Request for Comments on Final Staff Recommendations" (ACR), dated October 5, 2006, consistent with ALJ Meg Gottsetin's email titled "Direction for Reply Comments in R.06-04-009" (ALJ's email), dated October 23, 2006, and pursuant to Rules 1.9 and 1.10 of the California Public Utilities Commission's (CPUC or Commission) Rules of Practice and Procedure.

NRDC is a non-profit membership organization with a long-standing interest in minimizing the societal costs of the reliable energy services that a healthy California economy needs. In this proceeding, we focus on representing our more than 131,000 California members' interest in receiving affordable energy services and reducing the environmental impact of California's electricity consumption. TURN is a non-profit consumer advocacy organization which represents the interests of California's residential and small commercial customers. TURN has approximately 25,000 dues-paying members. UCS is a leading science-based non-profit working for a healthy environment and a safer world. Its Clean Energy Program examines the benefits and costs of the country's energy use and promotes energy solutions that are sustainable both environmentally and economically. WRA is a regional environmental law and policy center serving the Intermountain West States. Its Energy Program has been active before state public utility commission and other state and regional planning forums promoting clean energy investments for over 15 years.

We commend the Commission for the leadership role it has taken in establishing a greenhouse gas (GHG) emissions performance standard (EPS), which has now also been adopted into law on a statewide basis by Senate Bill (SB) 1368, signed by Governor Schwarzenegger on September 29, 2006. We strongly support the Commission's design and implementation of the EPS – an essential regulation that will protect Californians from the significant financial and reliability risks associated with additional investments in highly carbon-intensive generating technologies and help meet California's GHG reduction goals. We believe staff's final recommendations are largely consistent with SB 1368.

In these comments, we respond to the opening comments/legal briefs on the final staff recommendations submitted by various parties on October 18, 2006. We do not address issues that we have previously commented on in this proceeding. We refer the Commission to our "Opening Comments and Legal Brief on Final Workshop Report and Staff Recommendations Regarding the Greenhouse Gas Emissions Performance Standard of the Natural Resources Defense Council (NRDC), The Utility Reform Network (TURN), the Union of Concerned Scientists (UCS), and the Western Resource Advocates (WRA)" (Opening Comments) dated October 18, 2006, for a summary of our final positions on the implementation and design details of the EPS. Our reply comments are summarized as follows:

- We strongly recommend that the Commission reject SCE's proposal to allow LSEs to calculate an average emissions factor for a group of facilities supplying an unspecified resource contract.
- We disagree with SDG&E/SCG that the CEC's "Proposed Methodology to Estimate the Generation Resource Mix of California Electricity Imports" should form the basis for the imputed emissions rate for system power.

- We support IEP's request that the EPS should consider the emissions of all GHGs on a CO2-equivalent basis.
- We support ALJ Gottstein's proposed definition of "new ownership investment" as "any investment that is intended to extend the life of one or more units of an existing baseload powerplant for five years or more…" New ownership investments should not be defined only by increases in rated capacity.
- We disagree with EPUC/CAC that bottoming-cycle cogeneration technology should be excluded from the definition of "powerplants" under SB 1368.
- We urge the Commission to dismiss EPUC/CAC's interpretation that SB 1368 grants compliance to all existing gas-fired cogeneration facilities.
- SDG&E/SCG's "emissions avoided" approach is less accurate than the "conversion approach" for calculating credit for the used thermal load from cogeneration facilities.
- We strongly urge the Commission to dismiss PG&E's recommendation to use full load conditions in the documentation to evaluate emissions rate compliance with the EPS; documentation should instead use designed and intended heat rates to ensure an "apples-to-apples" comparison of emissions rates.
- We agree with EPUC/CAC that "annualized" and "average annual" capacity factor have the same meaning.
- We recommend that the Commission not predetermine methods of compliance for MJUs, as suggested by Sierra Pacific Power and PacifiCorp.
- CMUA/NCPA/SCPPA quotes from the Final Workshop Report a position on ESPs that is misattributed to NRDC/TURN/UCS/WRA.

DETAILED COMMENTS

We strongly recommend that the Commission reject SCE's proposal to allow LSEs to calculate an average emissions factor for a group of facilities supplying an unspecified resource contract.

Southern California Edison (SCE) proposes that load-serving entities (LSEs) should be allowed to calculate an average emissions factor for a group of facilities that supplies an unspecified resource contract (p. 10-11). We continue to assert that the EPS should be applied to all underlying facilities of a contract. If an LSE is able to identify the facilities that will supply the electricity in a contract, then they should **not** be allowed in any situation to average the emissions from these identifiable facilities, which would create a significant loophole for facilities that on their own would not pass the EPS. These contracts should be considered specified contracts, even if the contribution from each unit to the contracted power is unknown, and each individual facility under contract (that meets the EPS screening criteria) should be required to pass the EPS for the contract as a whole to be allowed.

We disagree with SDG&E/SCG that the CEC's "Proposed Methodology to Estimate the Generation Resource Mix of California Electricity Imports" should form the basis for the imputed emissions rate for system power.

San Diego Gas & Electric Company/Southern California Gas Company (SDG&E/SCG, p. 14) supports the use of the California Energy Commission (CEC) May 2006 "Proposed Methodology to Estimate the Generation Resource Mix of California Electricity Imports." We are concerned that the CEC proposed methodology (which has not yet been adopted by the CEC) underestimates the portion of California imports that are generated from coal. The proposed methodology determines the contribution of each resource fuel type to the import mix based on a simulation of market clearing prices that assumes that coal-based power is imported only to the extent that it sets the market-clearing price. This methodology would appear to underestimate the amount of imported coal power, because it relies solely on a marginal analysis, ignoring the infra-marginal contribution of coal when it is not the price-setting fuel type. For example, during the times in which California imports both coal and natural gas, natural gas would almost certainly set the market-clearing price and would be the only fuel type counted in the resource mix under the proposed CEC methodology. NRDC has commented on these concerns at the CEC workshop discussing the proposed methodology on June 7, 2006. (For our full comments on the CEC proposed methodology, see workshop transcript at http://www.energy.ca.gov/global_climate_change/inventory/documents/2006-06-07_workshop/2006-06-07_TRANSCRIPT.PDF, p. 70-73.)

This proposed methodology for determining the resource mix of imported electricity, which if adopted would feed into the CEC Net System Power resource mix, is one of the reasons we are concerned about the inaccuracy of using the Net System Power to calculate an imputed emissions rate for system power.   As we stated in our opening comments, we are willing to support using the Net System Power ***only*** if the highest emissions rate is used for each fuel type, since we have no way of knowing which technology is used for each fuel type. (See our October 18, 2006 Opening Comments, p. 24-25). For this reason, we also believe that the Division of Ratepayer Advocates (DRA) is incorrect to use an emission rate of 1.91 lb CO2/MWh for coal (p. 6), which is in fact *lower* than the lower end of the range of emission rates of existing coal plants (1.95-2.56 lb CO2/MWh) provided in data request #3 in this proceeding.

We support IEP's request that the EPS should consider the emissions of all GHGs on a CO2-equivalent basis.

The Independent Energy Producers Association (IEP) points to section 8340(g) of SB 1368 as intending the EPS to apply to the emissions of all GHGs, beyond just CO2 (p. 6-7). We support IEP in its recommendation that the Commission consider all GHG emissions, converted to CO2 equivalents, in the EPS.

We support ALJ Gottstein's proposed definition of "new ownership investment" as "any investment that is intended to extend the life of one or more units of an existing baseload powerplant for five years or more." New ownership investments should not be defined only by increases in rated capacity.

ALJ Gottstein proposed in an email dated October 23, 2006, to define "new ownership investment" (intended to encompass both repowering and major renovations to existing plants) as:

> 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 rated capacity of that powerplant. "Rated capacity" refers to the nameplate capacity of the plant, i.e., the plant's maximum rated output under speific conditions designated by the manufacturer and usually indicated in a nameplate phycially attached to the generator.

We support the first clause of the proposed definition: "Any investment that is intended to extend the life of one or more units of an existing baseload powerplant for five years or more." We urge the Commission **not** to adopt the "net increase in rated capacity" definition, as proposed by some parties, including Pacific Gas and Electric

Company (PG&E, p. 5) and SDG&E/SCG (p. 6). Under this interpretation, an existing high-emitting power plant with emissions above the EPS would not be subject to the EPS upon repowering or renovation if it did not increase the plant's rated capacity, although it would still present significant financial and reliability risks to California customers. Just as there is no basis in SB 1368 for a substantive size threshold (see p. 14 of our opening comments on the final workshop report), there is also no reason to apply a size threshold to repowering or renovations. SB 1368 clearly intends the EPS to apply to new *financial commitments*.

Thus, *any* new financial commitment that will extend the life of a baseload powerplant (as defined by SB 1368) for five or more years should be subject to the EPS. We are willing to support the full definition of repowering and renovations as proposed by the ALJ, *only* if the two conditions ("intended to extend the life of one or more units of an existing baseload powerplant for five years or more" and "results in a net increase in rated capacity of that powerplant ") continue to be separated by an "or" clause.

We disagree with EPUC/CAC that bottoming-cycle cogeneration technology should be excluded from the definition of "powerplants" under SB 1368.

Energy Producers and Users Coalition/Cogeneration Association of California (EPUC/CAC) suggest that bottoming-cycle cogeneration facilities should be excluded from the definition of "powerplant" in SB 1368 and thus also excluded from application of the EPS (p. 7-8) or deemed compliant with the EPS (p. 9). However, SB 1368, Section 8340(m) is clear that "powerplant means a facility for the generation of electricity…" A new financial commitment to any facility, including bottoming-cycle cogeneration technology, that produces electricity at an annualized capacity factor of at least 60% and delivers energy to California consumers should be subject to the EPS.

We urge the Commission to dismiss EPUC/CAC's interpretation that SB 1368 grants compliance to all existing gas-fired cogeneration facilities.

EPUC/CAC claims that the intent of SB 1368 is to deem all existing natural gas cogeneration facilities to be compliant with the EPS and thus requests the Commission adopt this position (p. 8-9). On the contrary, SB 1368 does not provide for such a stipulation. The statute is clear in its definition of "combined cycle natural gas" power plants in Section 8340(b). In addition, the inclusion of Section 8341(d)(3) for "calculation of emissions of greenhouse gases for cogeneration" indicates that SB 1368 intends for the EPS to apply to cogeneration facilities, with credit given for their used thermal load. We urge the Commission to dismiss EPUC/CAC's request in order to be consistent with SB 1368.

SDG&E/SCG's "emissions avoided" approach is less accurate than the "conversion approach" for calculating credit for the used thermal load from cogeneration facilities

SDG&E/SCG "emissions avoided" approach (p. 16-20) for calculating credit for cogeneration facilities is flawed for several reasons. First, the SDG&E/SCG approach requires making an arbitrary assumption about the efficiency of the gas boiler that would have been displaced by the heat output of the cogeneration facility. Secondly, not all cogeneration facilities are gas-fired, so it would be inaccurate to assume a general efficiency for all boilers. Third, SDG&E/SCG recommend drawing on CEC data to determine the general efficiency of gas boilers, but this data may not be representative of boilers located outside of California. Fourth, SDG&E/SCG recommend alternatively setting the boiler efficiency at the minimum state or local standards, but the cogeneration facilities under consideration are not necessarily new facilities and thus it would not be accurate to assume that the boiler that would have been used in its place would have efficiencies that meet the current standards. We continue to recommend using a "conversion" approach that provides credit only for thermal energy that is in fact used, as it is the more accurate approach and does not require making arbitrary assumptions. For a full discussion, please see our opening comments on the Final Workshop Report at pages 17-19. (See our October 18, 2006 Opening Comments, p. 17-19.)

We strongly urge the Commission to dismiss PG&E's recommendation to use full load conditions in the documentation to evaluate emissions rate compliance with the EPS; documentation should instead use designed and intended heat rates to ensure an "apples-to-apples" comparison of emissions rates.

PG&E recommends that guidance should be provided to LSEs to use full load conditions of a facility to calculate projected emissions (p. 6). As we explained in comments previously submitted in this proceeding, using the full load heat rate of a facility to calculate its emissions rate would underestimate the actual emissions rate of the facility and is inconsistent with the manner in which the EPS level is being set. (See "Reply Comments on Draft Workshop Report Regarding the Greenhouse Gas Emissions Performance Standard of the Natural Resources Defense Council (NRDC), The Utility Reform Network (TURN), the Union of Concerned Scientists (UCS), and the Western Resource Advocates (WRA)," September 15, 2006, p. 6-7.) We strongly urge the Commission to clarify that the documentation required to show compliance with the EPS include the use of designed and intended heat rates, **not** full load heat rates.

We recommend that the Commission not predetermine methods of compliance for MJUs, as suggested by Sierra Pacific Power and PacifiCorp.

Sierra Pacific Power (p. 3) misrepresents the final staff recommendation on the compliance process for multi-jurisdictional utilities (MJUs) by misquoting staff's position on SB 1368, Section 8341(d)(9)(B). This section of the Final Workshop Report (p. 53) does not represent staff's position but instead is a quote of PacifiCorp's position in post-workshop comments as summarized by the workshop report.

We do not believe it is necessary or appropriate as part of this rulemaking for the Commission to identify the various possible proposals for MJUs' compliance with the EPS, except to specify that it must satisfy the SB 1368 criteria in Section 8341(d)(9). We continue to encourage the Commission to allow opportunities for public comment on MJUs' proposals for alternative compliance as they are evaluated and implemented.

In addition, the MJU process laid out by SB 1368 is an alternative compliance route, not an "exemption route" as described by Sierra Pacific Power (p. 3).

We agree with EPUC/CAC that "annualized" and "average annual" capacity factor have the same meaning.

The ALJ's October 23, 2006 email requests comments from parties regarding their position on EPUC/CAC's request that SB 1368's term "annualized" capacity factor is defined as “average annual” capacity factor. We agree that “annualized” and “average annual” capacity factor have the same meaning.

CMUA/NCPA/SCPPA quotes from the Final Workshop Report a position on ESPs that is misattributed to NRDC/TURN/UCS/WRA.

California Municipal Utilities Association/Northern California Power Agency/Southern California Public Power Authority’s (CMUA/NCPA/SCPPA) quote a position from the Final Workshop Report on energy service providers (ESPs) that is misattributed to NRDC/TURN/UCS/WRA:

> ESPs operate fundamentally differently from the IOUs. Their procurement plans and transactions are not subject to the requirements of AB 57, therefore EPS compliance monitoring for ESPs must be conducted differently than that for the IOUs. The Revised Staff Proposal appears to present conflicting statements with respect to how ESP compliance with the EPS will be determined. EPS monitoring and compliance fails to reflect important distinctions between ESP and IOU compliance.

We would like to alert the Commission and other parties to this error in the Final Workshop Report on page 76 that misattributes this statement to our collective parties. Nowhere in our comments previously filed in this proceeding do we make this statement. We refer the Commission to page 7 of our October 18, 2006 Opening Comments on the Final Workshop Report for our position on the compliance process that we recommend for ESPs. Namely, although we believe the Commission should consider ESP’s existing reporting schedule in developing an ESP compliance process, it is imperative that the standard must be enforced on an upfront basis for all LSEs.

CONCLUSION

We commend the Commission for proactively seeking to establish a GHG performance standard that can be easily and quickly implemented. The standard is critically needed to protect Californians from the significant financial and reliability risks associated with new investments in highly carbon-intensive generating technologies and to help meet California’s GHG reduction goals. We support the staff’s final proposal for the EPS as being largely consistent with the requirements of SB 1368, and urge the Commission to adopt the modifications we suggest in these comments to make the EPS fully consistent with SB 1368. We continue to look forward to further developing and finalizing the details of the EPS with the Commission and other parties.

Dated: October 27, 2006

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