Implementation of SB 1368 Emission Performance Standard

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Chapter 1: Introduction

The purpose of this paper is to raise issues which the Energy Commission must address in adopting a greenhouse gases emissions performance standard and implementing regulations for local publicly-owned utilities as required by SB 1368 (Chapter 3, Section 8340, Division 4.1 of the Public Utilities Code). These issues will be discussed by parties at the Electricity Committee's December 8, 2006 workshop. Energy Commission staff will then develop draft proposals to be discussed at a subsequent workshop(s). After considering all input on staff's draft proposal, the Electricity Committee will recommend an emissions performance standard and implementing regulations for adoption by the Energy Commission.

Background

Due to concerns regarding the effects of global warming and the likelihood of future federal greenhouse gas emissions regulations, the Legislature enacted Senate Bill 1368 to reduce consumer exposure to the risk of future pollution control costs and potential exposure to reliability problems in electricity supplies. The Legislature concluded that to have a meaningful impact on climate change, goals for reducing greenhouse gas emissions must be applied to the State's electricity consumption and its production.

As the western state's largest electricity consumer, California must provide clear guidance on meaningful emission performance standards for electricity procurement. The Legislature determined that a policy and emissions performance standard applied to long-term electricity procurement by all of the State's load-serving entities is necessary to meet the State's goals for reducing greenhouse gas emissions.

Senate Bill 1368 requires the California Energy Commission, in consultation with the California Public Utilities Commission (CPUC) and the California Air Resources Board (ARB), to establish and adopt by June 30, 2007, greenhouse gases emission performance standard and implementing regulations for all long-term baseload generation commitments made by local publicly-owned electric utilities. The CPUC is required to establish an emission performance standard for the investor owned utilities by February 1, 2007. The performance standard is not to exceed the rate of greenhouse gases emitted per megawatt-hour for combined-cycle, gas turbine baseload generation. The regulations also require an output-based methodology for calculating and enforcing the emission performance standard and a process for re-evaluating and revising the emission standard as necessary.

Chapter 2: Procedural Issues

Some stakeholders have argued that SB 1368 should be read to require Energy Commission adoption of the standard and implementing regulations on June 30, 2007, but not require Office of Administrative Law (OAL) approval by that date. However, SB 1368 requires enforcement to “begin immediately upon the establishment of the standard.” (Pub. Utilities Code §8341(e)(1).) To enable the Energy Commission to begin enforcing the standard, it must be adopted as a regulation pursuant to OAL review under the Administrative Procedure Act and filed with the Secretary of State. (Gov’t Code §11340.5(b).) The timeline presented below for adoption of this rulemaking is structured to accommodate OAL’s approval and filing with the Secretary of State by the statutory deadline.

In order for the Energy Commission to have enforceable regulations enacted by June 30, 2007, staff has identified the following stakeholder consultation and regulation processing schedule:

- **October through January** – Consult with CPUC, ARB, and other stakeholders to develop proposed regulations.
- **December 8, 2006 –** Hold first Committee workshop to discuss interpretive implementation issues and regulatory components needed to comply with SB 1368.
- **December 11 –** Begin writing text of proposed regulations.
- **January 8-19** – Begin preparing the Notice of Proposed Action (NOPA), text of proposed regulations, informative digest, Fiscal/Economic Impact Statement, Initial Statement of Reasons.
- **January 11 and 18, 2007–** Dates reserved for subsequent Committee workshops on the proposed emission standard and implementing regulations.
- **January 22, 2007** – Submit Fiscal/Economic Impact Statement to Department of Finance for review and signature (Review may take up to 30 days).
- **January 25, 2007 –** CPUC adopts its EPS.
- **February 20, 2007** – Submit NOPA and accompanying documents to OAL.
- **March 2, 2007** – NOPA and accompanying material published by OAL
- **April 16, 2007** – Any 15-day language changes must be noticed.
- **May 2, 2007** – Energy Commission Adoption of regulations.
- **May 2-18, 2007** – Finalize rulemaking package.
- **May 18, 2007** - Submit entire rulemaking package to OAL for approval (30 working day review period.
- **June 29, 2007** - OAL approval/Filing with the Secretary of State.

Another issue is whether the Energy Commission should or must complete the entire rulemaking at once or whether a phased adoption approach is possible. This might entail adopting an emission standard for carbon dioxide (CO_2) by the June 30, 2007 deadline, and a standard for other greenhouse gases as reliable measurement data become available. The issue of the potential for phased regulations should be explored at the hearings (See Chapter 5 of this paper for more detail).

Chapter 3: Affected Entities & Financial Commitments

This section examines which publicly-owned utilities and which kinds of long-term financial commitments are subject to compliance with the emissions performance standard (and implementing regulations) required by statute. The following section will examine the kinds of financial commitments subject to the statute. Chapter 4 will discuss the types of generating facilities addressed.

Affected Public Utilities

SB 1368's definition of local publicly-owned electric utilities is found in Public Utilities Code 9604:

> *(d) "Local publicly owned electric utility" as used in this division means*
>
> - *a municipality or municipal corporation operating as a "public utility" furnishing electric service as provided in Section 10001:*
>
> *"Public utility" as used in this article, means the supply of a municipal corporation alone or together with its inhabitants, or any portion thereof, with water, light, heat, power, sewage collection, treatment, or disposal for sanitary or drainage purposes, transportation of persons or property, means of communication, or means of promoting the public convenience*.]
>
> - *a municipal utility district furnishing electric service formed pursuant to Division 6 (commencing with Section 11501),*
> - *a public utility district furnishing electric services formed pursuant to the Public Utility District Act set forth in Division 7 (commencing with Section 15501),*
> - *an irrigation district furnishing electric services formed pursuant to the Irrigation District Law set forth in Division 11 (commencing with Section 20500) of the Water Code, or*
> - *a joint powers authority that includes one or more of these agencies and that owns generation or transmission facilities, or furnishes electric services over its own or its member's electric distribution system*

In general terms, the five categories of POU's include, municipalities (cities), municipal utility districts, public utility districts, irrigation districts and joint powers authorities. In California, these include the following entities:

- Cities – Alameda Power & Telecom, Anaheim, Azusa Light & Water, Banning Electric Utility, Biggs, Burbank Water & Power, Cerritos, Colton, Corona, Glendale Water & Power, Gridley, Healdsburg, Lodi Water & Electric, Lompoc Utility Department, Los Angeles, Moreno Valley, Needles, Palo Alto, Pasadena Water & Power, Redding Electric Utility, Riverside, Roseville, Shasta Lake, Silicon Valley Power, Ukiah Public Utilities, and Vernon Light & Power
- Municipal Utility Districts – Lassen MUD, Sacramento MUD
- Public Utility Districts – Truckee-Donner PUD
- Irrigation Districts – Imperial ID, Merced ID, Modesto ID, and Turlock ID
- Joint Powers Authorities – Pittsburg Power Company, Southern California Public Power Authority (SCPPA), and Northern California Power Authority (NCPA).

  Pittsburg Power Company is a joint powers authority between the City of Pittsburg and the Redevelopment Agency, operating as Island Energy on Mare Island.

  SCPPA is a joint powers authority with 12 public power agency members which finances the construction or acquisition of power plants or transmission lines. The members are: Anaheim, Azusa, Banning, Burbank, Cerritos, Colton, Glendale, Imperial Irrigation District, Los Angeles Department of Water and Power, Pasadena, Riverside and Vernon.

  NCPA's members include the cities of Alameda, Biggs, Gridley, Healdsburg, Lodi, Lompoc, Palo Alto, Redding, Roseville, Santa Clara, and Ukiah, as well as the Bay Area Rapid Transit District, Port of Oakland, the Truckee Donner Public Utility District, and the Turlock Irrigation District, and whose Associate Members are the Lassen Municipal Utility District, Plumas-Sierra Rural Electric Cooperative, and the Placer County Water Agency.

Unaffected Public Utilities

The Energy Commission operates other programs affecting public utilities. Some of these are not considered "locally-owned" public utilities as defined in PUC Section 9604 and included in the SB 1368 definition. These include two large water agencies--the Metropolitan Water District (MWD) and the California Department of Water Resources (CDWR); and a federal agency--the Western Area Power Administration (WAPA). The water agencies have no retail customers, and are net purchasers of energy.

McAllister Ranch ID is a planned community on the north side of Bakersfield it is not a member of CMUA and we are unclear about its status. We welcome clarification about the status of any other local publicly owned utility.

Long-Term Financial Commitment

This section examines the statute's meaning and application of "long-term financial commitments". It presents the statutory language, raises questions for discussion, and cites possible guidance in the statute's provisions and the CPUC's October 2, 2006 final staff report.

> Section 8340
> *(j) "Long-term financial commitment" means either a new ownership investment in baseload generation or a new or renewed contract with a term of five or more years, which includes procurement of baseload generation*.

In reviewing SB 1368 and determining how best to craft regulations to implement the statute, it has become increasingly clear that the phrase a "new ownership investment" needs to be defined.

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?

There are several possible definitions for a "new ownership investment":

- Ownership may refer only to the purchase of facilities that will be owned directly by the POU.
- Ownership may also include participation in a joint powers authority.
- First time acquisition of a baseload facility;
- Expenditure of additional dollars on an existing facility that will create, preserve or extend a baseload function for more than 5 years;
- Expenditure of additional dollars on an existing facility including that which will create, preserve or extend a baseload function for any period;
- Any planned expenditure on a facility including that for routine replacement, repair of failed or degraded equipment, or compliance with new regulations;
- Any planned expenditure on a facility, including refinancing.

The statute's intent and application language does not provide significant guidance on which investments are to be addressed. The intent suggests key goals are to reduce consumer exposure to the risk of future pollution control costs and reliability problems in electricity supplies. We will have to look to the entire content of the statute to determine relevant expenditures.

Question 3.2

How does the intent of the legislation guide our choice?

Question 3.3

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

In a JPA, two or more POUs and a public financing authority actually own the powerplant. The POUs then contract with the JPA for the entire output of the powerplant. There are many more JPAs other than the well-known NCPA and SCPPA. For example, the Consumes and Intermountain power plants are owned through a JPA. This ownership form represents a financing and risk management structure, with non-POU involvement. The proposed regulations must define whether a joint powers authority constitutes ownership or a contract, because the statute uses slightly different language to describe the coverage of ownership and contracts.

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”?

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?

Major facility modifications such as a repower or replacement might change the GHG gases output or total emissions amount. Some parties suggest that investments which result in either an increased emissions rate or total GHG emissions output should be considered an “investment” in baseload generation. This argument assumes the statutory intent is to reduce GHG emissions from the power system. Under this assumption, “investment” would not include financing or repairs and maintenance that do not effect emissions.

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?

Some POUs currently own or contract for generation from power plants which may need to be modified to meet other environmental regulations, such as reducing use of sea water for cooling. In the case of coastal steam boilers, it is possible that the resulting loss of efficiency would push the older unit’s GHG emissions per megawatt hour above the standard.

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?

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?

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?

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?

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?

Question 3.12

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

Based upon the CPUC's October 2, 2006 staff report and the comments filed in that docket, parties seem to agree that routine replacement and repair expenditures are not investments for the purposes of this statute. If any party believes that such expenditures should be treated as investments, staff requests that they provide reasons.

Question 3.13

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

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

The statute defines baseload power plants as those operating at an annualized capacity factor of 60% or more.

Question 3.13

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 have not identified any ambiguities regarding the definition of new or renewed contracts with a term of five or more years, other than the question of whether a joint powers authority is a contract or an ownership arrangement. Two related issues are discussed in other sections of the paper:

- (Chapter 4) what is procurement of baseload generation
- (Chapter 5) whether the intent of this clause could be avoided by '"slicing and dicing" through chaining multiple contracts over time.

In the context of local publicly-owned utilities, two types of arrangement might be considered ownership. The first is straight forward, purchase of a new powerplant that will be owned by the local POU. There is another form of legal control employed by many POUs, the joint powers authority. In this arrangement, two or more POUs plus a public financing authority actually own the powerplant. The POUs then contract with the JPA for the entire output of the powerplant.

There are many more JPAs other than the well-known NCPA and SCPPA. For example, the Cosumnes and intermountain power plants are owned through a JPA. This ownership form represents a financing and risk management structure, and no non-POUs are involved. The proposed regulations must define whether a joint powers authority constitutes ownership of a facility or a contract for the procurement of generation, because the statute uses slightly different language to describe the coverage of ownership and contracts.

Question 3.14

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

Question 3.15

Are there any other issues related to JPAs that should be addressed?

Chapter 4: Emissions Performance Standard

The statute requires the emissions standard for the POU's to be consistent with that developed by the CPUC for its jurisdictional load-serving entities. Since this paper was prepared prior to the CPUC's adoption of a standard for load-serving entities, it raises issues that have been examined in the CPUC process and examines POU-specific issues which may provide a basis for modifying the Energy Commission's standard.

> *(e) (1) On or before June 30, 2007, the Energy Commission, at a duly noticed public hearing and in consultation with the commission and the State Air Resources Board, shall establish a greenhouse gases emission performance standard for all baseload generation of local publicly owned electric utilities at a rate of emissions of greenhouse gases that is no higher than the rate of emissions of greenhouse gases for combined-cycle natural gas baseload generation. The greenhouse gases emission performance standard established by the Energy Commission for local publicly owned electric utilities shall be consistent with the standard adopted by the commission for load-serving entities. Enforcement of the greenhouse gases emission performance standard shall begin immediately upon the establishment of the standard. All combined-cycle natural gas powerplants that are in operation, or that have an Energy Commission final permit decision to operate as of June 30, 2007, shall be deemed to be in compliance with the greenhouse gases emission performance standard.*

The CPUC staff proposed 1,100 pounds carbon dioxide per megawatt-hour as an Interim Emissions Performance Standard in its October 2, 2006 Final Workshop Report. The standard was selected from proposals ranging from 800 to 1,400 lbs CO2/MWhr, and the earlier Revised Staff Report's recommendation of 1,000 lbs CO2/MWhr (0.46 metric tons CO2/MWhr)[1]. The CPUC staff proposed EPS's of 1,000 or 1,100 lbs CO2/MWhr (0.50 metric tons CO2/MWhr) appear to be a compromise between the 800 lbs CO2/MWhr that the most efficient modern combustion turbine combined cycle plant could achieve, and the 1,400 lbs CO2/MWhr that might envelope the majority of natural gas burning technologies (e.g., steam cycle boiler, simple cycle combustion turbine, reciprocating engine, and a range of combustion turbine combined cycle units).

A proposed standard of 1,100, or 1,000, lbs CO2/MWhr is equivalent to a power plant unit with an effective heat rate, in higher heating value (HHV)[2], of:

	Typical Fuel CO2 emission factor	Effective Heat Rate @ an EPS of 1,000 lbs	Effective Heat Rate @ an EPS of 1,100 lbs

[1] Conversion: pounds to metric tons, multiply by 0.454×10^3.

[2] Heating Value: traditionally, heat rates in the USA and of boiler units is specified in higher heating value, while Europe and combustion turbines generally use lower heating value. For this discussion and more direct comparison, the higher heating value is used unless otherwise stated.

Natural gas HHV = 1.11 x LHV

Bituminous coal HHV = approx. 1.05 x LHV

	(lbs CO_2/mmBtu)	CO_2/MWhr	CO_2/MWhr
Natural Gas	116.4	8,590 Btu/kWhr	9,450 Btu/kWhr
Fuel Oils	158.0	6,330 Btu/kWhr	6,890 Btu/kWhr
Bituminous Coal	204.0	4,900 Btu/kWhr	5,390 Btu/kWhr
Petroleum Coke	222.9	4,490 Btu/kWhr	4,940 Btu/kWhr

These heat rates are calculated using a default value for the amount of carbon (fuel CO_2 emission factor) in the fuel that is converted to CO_2 through combustion. Specific coal types (e.g., bituminous versus sub-bituminous differ by about 5 percent) and oil fuels have varying carbon content, so the above heat rates are estimates for illustration of what types of units and fuels might meet the proposed EPS . Real world unit or contract compliance with the EPS should be tied to the specific fuel and unit operations characteristics for that unit(s).

Some base load natural gas-fired Western Electricity Coordinating Council (WECC) electricity production units have a heat rate less than 9,450 Btu/kWhr and would satisfy the EPS, but almost no natural gas units (that are not combined cycles) operate at a heat rate of less than 8,590 Btu/kWhr. Staff is not aware of any fuel oil-, coal- or petroleum coke-fired base loaded power generation units that could achieve or even approach the effective heat rates shown above.

Coal

Typical coal-fired technologies and their generic heat rates.

- 10,000 Btu/kWhr traditional pulverized coal
- 8,500 Btu/kWhr supercritical pulverized coal
- 11,000 Btu/kWhr circulating fluid bed boilers
- 8,200 Btu/kWhr integrated coal gasification combined cycle with “F” turbines
- 7,500 Btu/kWhr integrated coal gasification combined cycle with “H” turbines

Question 4.1

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

Question 4.2

Would a demonstration project for advance coal-fired technologies and/or CO_2 sequestration need to operate at more than 60% capacity factor or for more than 5 years, requiring the unit(s) to meet the EPS?

Fuel Oils

Typical heat rates for fuel oil-fired units would be similar to the heat rates shown for the coal technologies above and would not meet the EPS. However, it is highly unlikely that base loaded fuel oil-fired units would be used in the WECC. Fuel oil use for electricity production has been significantly curtailed due to air pollutant emissions regulations and costs. However, it is still used as a backup fuel to natural gas, generally in peaking turbines and reciprocating engines, or in back up emergency generators.

Questions 4.3

If fuel oil is the designated back up fuel for a baseload unit:

- How are the CO2 emissions from potential, but uncertain back up fuel use rates calculated and included in the unit CO2 emissions; and
- How are the CO2 emissions associated with actual fuel use calculated and included in the unit CO2 emissions?

Petroleum Coke

Petroleum coke is a by-product of oil refinery operations. Heat rates and technologies would be similar to coal heat rates and technologies and would not meet the EPS in electricity generation units.

Question 4.4

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

Micro/Small Combustion Turbines

Most small and micro turbines would not be able to meet the proposed EPS if used as base load generation units. Typical heat rate are shown below:

- 13,000 Btu/kWhr natural gas fired < 1 MW micro turbine
- 15,000 Btu/kWhr natural gas fired 1 MW turbine
- 11,000 Btu/kWhr natural gas fired 7 MW turbine
- 11,000 Btu/kWhr natural gas fired 15 MW turbine

Question 4.5

Are micro/small combustion turbines used in baseload applications?

Cogeneration/Combined Heat & Power

Cogeneration, or combined heat and power, is the sequential production of electricity and useful thermal energy (e.g., steam, hot water, or hot gases) for an industrial application (e.g., cement production, enhanced oil recovery, food processing, oil refining, etc). California encourages the use of cogeneration.

The CPUC is proposing a credit for cogeneration by converting the useful thermal output component to a MWhr-equivalent.

$$\frac{\text{Total Emissions lbs CO2}}{\text{MWhr net electricity production} + [\text{mmBtu useful thermal}/(3.413\ \text{mmBtu/MWhr})]}$$

$$\text{MWhr}_{\text{equivalent}}$$

However, the conversion assumes a plant operating at 100% efficiency, or a heat rate of 3,413 Btu/KWhr. In other methods discussed by the CPUC, the useful thermal energy is discounted by 50% before converting the output to MWhr-equivalent, or useful thermal energy is assumed to come from an 80% efficient boiler.

Waste Fuels

The following fuels may be considered waste fuels:

- Petroleum coke
- Flared gases from oil production
- Flared gases from oil refining
- Flared landfill gases
- Biogases from digesters
- Municipal solid waste/refuse derived fuels
- Organic and cellulose waste/by-products

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?

Greenhouse Gases

The CPUC's October 2, 2006 staff report is not clear on how the proposed EPS for CO2 will address the other greenhouse gases: methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons and sulfur hexafluoride. Emission rates of non-CO2 greenhouse gases from electricity production and cogeneration may be important since the non-CO2 greenhouse gases have higher global warming potential (see table below) compared to CO2.

Greenhouse gas	Global Warming Potential (relative to CO_2)
Carbon dioxide (CO_2)	1
Methane (CH_4)	23
nitrous oxide (N_2O)	296
Hydrofluorocarbons (HFCs)	120 -12,000
Perfluorocarbons (PFCs)	5,700 – 11,900
sulfur hexafluoride (SF_6)	22,200

Third Annual Assessment, IPCC 2001

CO_2 emissions can be readily calculated as a function/by-product of fuel combusted. N_2O is a by-product of nitrogen and high temperature combustion. It is not typically measured directly, but generally calculated via an emission factor and fuel use. SF_6 is a transformer cooling/insulating material. SF_6 emissions from electricity production due to spills and leakage are estimated via tracking of purchases, spills, and disposal. The HFCs and PFCs are common refrigerants; emission rates are estimates of leaks and spills tracked via tracking of purchases, spills, recycling and disposal.

Methane emissions from electricity production come from unburned fuel in the exhaust stack flue gases, and pipeline and flange leaks. Unburned methane in the exhaust stack is measured annually on some units such that annual emission rates can be calculated based on the measured emission factor and the annual fuel use. Leakage rates are more complex and controversial – partly due to uncertainly about actual leak rates and where to draw the plant boundary (i.e., how close to the cradle – well head – is the boundary drawn) to capture the power plants portion of the leakage.

Question 4.7

If the CPUC adopts a CO_2-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-CO_2 emission rates from electricity production to be able to set a CO_2 and non-CO_2 EPS?

Renewables/Non-Renewables Blended Contracts

Some POU contracts with renewables are firmed by pairing the renewables with either a unit-specific contract (rare) or a system purchase. These contracts are used to both meet the POUs' Renewable Portfolio Standard and to meet the POUs' overall energy and capacity needs. By law, the POUs have a wider range of contract types to meet the RPS than do the IOUs.

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?

Unit/Facility Electricity Production

This statute is applicable at the powerplant or facility level. A powerplant or facility may have multiple units on site. Ownership or contracts might be written with a facility or with a unit at a facility.

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?

Net Emissions

SB 1368 calls for the consideration of “net emissions” when determining the greenhouse gases emissions rate associated with electric generation. Specifically, the law states:

> *“In determining the rate of emissions of greenhouse gases for baseload generation, the Energy Commission shall include net emissions resulting from the production of electricity by the baseload generation.” [Section 8341(e)(3)]*

The following sections provide more detail about the types of factors considered in the netting process for positive and negative contributions of greenhouse gases from electricity generation. First, the statute allows consideration of useable energy output in co-generation processes. The thermal output can be “netted” from the greenhouse gases emissions rate under the emission performance standard.

Second, the net greenhouse gases reductions associated with biomass, biogas, and landfill gas are considered in the determination of a net emissions rate under the standard. The statute also calls for consideration of the net reductions of greenhouse gases associated with the use of these renewable forms of energy. The Energy Commission seeks comments on the range of possible approaches to establish net greenhouse gases emissions from biomass, biogas, and landfill gas used to generation electricity. The final CPUC staff workshop report for the interim emissions performance standard summarized comments on this topic in the following way:

> *“Most parties commenting suggested assigning a zero emissions rates (sic) for all renewables, including those from biogenic sources…(other parties) suggested net emissions be considered for biogenics and zero emissions rate for other renewables…” [Final staff report, R.06-04-009, Oct. 2, 2006, p. 35]*

Finally, the statute allows for the netting of carbon dioxide prevented from entering the atmosphere through storage in geologic formations. The Energy Commission seeks comments on the range of possible approaches to incorporate geologic sequestration into the net emissions calculations of greenhouse gases emissions from baseload facilities.

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?

Unspecified Sources of Long-Term Contracts

At the CPUC, the ESPs indicated they do not sign contracts of greater than five years so the standard would not need to apply to unspecified resources in order to meet their market model. On the other hand, small POUs have been using long-term contracts with marketers or portfolio managers to meet their small baseload acquisitions.

Question 4.12

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

Reliability and Cost Considerations

The statute directs the Energy Commission to consider the effect of the standard on reliability and costs to consumers. These concerns would be different for the POUs outside the footprint of the California Independent System Operator, as the requirements and cost recovery may be different in other control areas such as LADWP, SMUD, and Imperial Irrigation District.

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?

Chapter 5: Compliance & Enforcement Alternatives

This section discusses alternatives for demonstrating compliance with the emissions performance standard and for verifying that physical resources and contractual agreements meet the EPS. First, the desirable attributes of a compliance and verification process are enumerated. Second, three types of compliance and verification mechanisms – self-certification, prior review and approval, and performance monitoring - are discussed. Third, the data needed to verify that specific resources are in compliance are discussed; this highlights the possibility that different compliance and verification procedures may be appropriate for the procurement of different resources.

CPUC Staff Recommendations for EPS Compliance

SB 1368 applies an emissions performance standard to commitments of five years or longer for baseload energy, defined as energy from a resource that was designed and intended to operate at or above a 60 percent annual capacity factor. While the CPUC initially recommended that the standard be applied to commitments of 25 MW or more, no such threshold is assumed in this document; the implications of its absence are noted below where relevant.

The CPUC staff's Final Workshop Report[3] recommends a "gateway" standard for the IOUs, rejecting a standard that requires on-going monitoring. For the ESPs, it recommends self-certification:

> "IOUs will be subject to [a] gateway screen…the [CPUC] will develop a filing/review process for the ESPs that comports with their current reporting processes (Final Workshop Report, p. 41)."

While no further definition of the proposed compliance mechanism for ESPs is provided in the report, it is likely that CPUC staff will follow the recommendation of Constellation Energy recommended that the CPUC allow ESPs to self-certify as part of their resource adequacy compliance filings at the CPUC:

> "Constellation suggests that ESPs address whether or not they secured capacity or energy from covered contracts within the regular compliance filings made annually and monthly in the resource adequacy effort. Such an approach would provide a simple, administratively efficient and timely means of informing the [CPUC] of EPS compliance (Final Workshop Report, p. 77)."

Several POU's filed comments with the CPUC recommending that the POU's, like the ESPs, be allowed to self-certify for purposes of state regulatory review over their procurement practices. The CPUC Workshop Report does not specifically indicate why staff recommends a less onerous standard for the ESPs. Several reasons for doing so were presented by intervenors in comments and are discussed below.

Desirable Compliance and Verification Attributes

Effectiveness: The compliance mechanism must first and foremost ensure that the intent of the legislation is realized. It must allow for verification of claims, and minimize opportunities to circumvent legislative intent. To the extent the standard and associated regulations leave room to behave strategically and avoid the standard, the mechanism must foreclose opportunities or provide disincentives to the extent practicable.

Provide Transparency: The criteria used in applying the standard should, to the extent possible, be clear and estimable and minimize the need for case-by-case review. This allows all interested parties to assess whether a proposed facility or contract meets the standard and readily understand how a decision regarding compliance was reached.

[3] "Final Workshop Report: Interim Emissions Standard Program Framework," (R.06-04-009, CPUC Staff, October 2, 2006)

Minimize Uncertainty: Compliance and verification should be structured to minimize uncertainty. Where self-certification is not feasible and prior review and approval of procurement proposals is deemed necessary, such review should be completed as quickly as possible. The need for compliance mechanisms which involve assessments after the resource has been procured should be weighed against the resulting uncertainty, which may entail risks to buyers and sellers of energy products and thus impose a cost on ratepayers.

Administrative Ease: The compliance mechanism should, where possible, minimize the reporting burden and rely on data produced for other purposes.

Question 5.1

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

Compliance and Verification Alternatives

There are three broad alternatives for compliance and verification. These are self-certification, prior review, and performance monitoring:

- Self-certification requires that the publicly-owned utility certify that facilities and contracts meet the standard. This is the mechanism that has been proposed by the CPUC staff as the compliance mechanism for energy-service providers.
- Prior review and approval (also known as a “gateway standard”) would require that the Energy Commission certify up front that a facility or contract meets the standard. Once certified, it would be considered as meeting the standard throughout its life, absent modifications that would trigger review. This is the mechanism that has been suggested by CPUC staff for IOU compliance. As stated in the Final Workshop Report:

  > “No parties proposed an alternative approach [to a gateway standard] to administration of the program.
  >
  > The principal reasons that parties supported the gateway approach are because it minimizes contract approval uncertainty, sends clear signals regarding compliance, and does not require ongoing administrative oversight and therefore is relatively straightforward to manage (p. 19).”

- Performance monitoring is necessary if a standard and associated regulations direct corrective actions or if penalties can be assessed after certification where conditions imposed upon approval or assumed to prevail after approval are not realized.

More than one of these mechanisms could be used; the appropriate compliance and verification mechanism may depend on the specific type of physical or contractual resource being procured by the POU. Such flexibility may ensure that the compliance and verification process meets each of the objectives discussed above to the greatest extent possible.

Question 5.2

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

Self-Certification

Self-certification is likely to be proposed as a compliance option by the POUs based on their comments in R.06-04-009 at the CPUC. These comments assert that self-administered POU procurement far more closely resembles procurement by ESPs. BY contrast, long-term procurement by the IOUs already requires CPUC oversight and prior approval.[4]

Self-certification could take several forms; that chosen could depend upon the type of resource for which a financial commitment is being made.

- Implicit self-certification, where the financial commitment itself constitutes testimony that the resource is SB 1368 compliant and no other action is necessary.
- Evidence presented to the POU's governing board that the resource is SB 1368 compliant.
- For contracts, an optional clause in the contract that contains the requirement that the resource meet the standard and allocates the risk for possible consequences if energy deliveries under the contract are subsequently found to be out of compliance.
- 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.
- The filing of a certificate of compliance as above after the commitment has been made.
- A periodic compliance filing, e.g., annually, that enumerates the commitments made during the preceding period that are subject to the standard. This filing may also include statements of intent to enter into such commitments in the upcoming reporting period. This can be coordinated with, if not incorporated into, existing filings so as to minimize administrative burden. Examples of this form include (a) year-ahead resource adequacy compliance filings (pursuant to AB 380), (b) filings for the Net System Power Report, and (c) filings with the Climate Change Action Registry.

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[4] This is true in that state agencies have not historically had jurisdiction over their contracts with energy suppliers, but in numerous other respects related to facility ownership and long-term contracts they more closely resemble the IOUs:

(a) POUs own and operate generation facilities, ESPs do not;
(b) POUs have long-term load obligations whereas the obligations of ESPs are assumed in at the ESP's discretion and are, as a rule for a shorter term. This markedly reduces the incentives for the ESP to enter into contracts of 5 years or longer;
(c) ESPs are licensed by the CPUC and, as such, may be easily and severely penalized for false testimony with respect to meeting the EPS;
(d) ESPs have a ready mechanism for self-certification (year- and month-ahead resource adequacy compliance filings), POUs (at least those outside the CA ISO control area) do not.

Self-certification is feasible when it is possible to verify compliance using readily available data. For example, the estimated emissions and operating profile of a new facility are among the data submitted to local permitting authorities. Similarly, information regarding the generation and fuel use/emissions of many existing resources is available from a number of public sources.

In those instances where the compliance of a resource cannot be verified with readily available data, self-certification may require a monitoring or auditing procedure that consistently, selectively or randomly verifies claims.

Pros: Minimizes burden of compliance.

Cons: May not be appropriate for resources whose eligibility is not clearly determined by reference to the standard. This may occur, for example, if a contract contains clauses which raise questions as to whether or not it is subject to or meets the standard, in which case a formal determination may be desirable. It may also occur if the standard itself imposes conditions or constraints, e.g., on future operation, in which case performance monitoring may be necessary.

Question 5.3

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

Question 5.4

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

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?

Prior Review and Approval

Prior review and approval would require that the Energy Commission certify a facility or contract as meeting the standard. Once certified, it would be considered as meeting the standard throughout its life, absent modifications to the facility/contract that would trigger review. Prior review and approval cannot be used if the eligibility of a resource is contingent upon outcomes which are not known until after certification is granted.

Pros: Prevents a subsequent finding that the resource was non-compliant. Once completed, eliminates uncertainty as to whether the resource will continue to meet the EPS, thus reducing compliance risk for both the POU and, in the case of a contract, the seller.

Cons: If not done in a timely fashion, review and approval may preclude investments which are available for only a brief period.

Question 5.6

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

Performance Monitoring

Performance monitoring is necessary if the eligibility of a facility or contract is dependent upon events, conditions or outcomes that occur after construction, purchase or signing. The potential need for performance monitoring thus depends largely upon the standard itself. If, for example, approval of a contract, is conditioned upon one or more powerplants, generation owners, or the POU meeting post-signing performance requirements, the regulations will need to describe how such performance will be monitored and evaluated. This requires establishing protocols for collecting and evaluating data, ensuring due process, and enforcing corrective action in the event of a finding of non-compliance.

Pros: Allows conditions imposed during self-certification or prior review, and assumptions about operating performance and emissions, to be confirmed by empirical physical and financial data.

Cons: Imposes additional compliance costs on POUs and regulatory authorities. Creates additional uncertainty regarding the eligibility of resources under the standard.

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?

Compliance Mechanisms and Specific Commitments

The suitability of a given compliance and verification mechanism can be expected to vary depending upon the specific characteristics of the commitment being made and the availability and nature of data needed to evaluate whether or not the commitment meets the EPS. For example, purchase of a recently constructed gas-fired combined cycle plant can be reasonably expected to meet the standard; the ready availability of historical data on its emissions may obviate the need for a detailed compliance filing or verification procedure. A minimum capacity contract must take energy provisions in every hour of the year - one that does not specify a source for the energy - arguably calls for a more complex verification process.

Verification of Physical Resources

The emissions performance standard required by SB 1368 must apply to all new investment that involves baseload generation. All units that are “designed and intended” to provide baseload energy come under the standard.

It is likely that the data needed to evaluate whether physical resources brought under the control of the utility meet the EPS will be available prior to the acquisition of the resource. In these instances, self-certification would seem to be a reasonable and appropriate compliance mechanism. The results of (required) tests of new and repowered facilities can be tested to verify that they meet a specific lbs CO_2/MWh emissions standard.

- For new facilities and repowerings that come under the Energy Commission’s jurisdiction, heat rate data and the planned operational profile filed as part of the siting process can be used to assess whether the facility meets the EPS. EPS compliance can be an additional component of the LORS (Laws, Ordinances, Regulations and Standards) determination in the Energy Commission’s certification process.
- For facilities for which a Small Power Plant Exemption (SPPE) is requested, heat rate data and the planned operational profile can be solicited in a staff data request. SB1368 compliance can be considered when staff is assessing whether or not the project would have an adverse impact on the environment.
- For new facilities of less than 50 MW and for repowerings not subject to CEC jurisdiction, sufficient heat rate data and information regarding the planned operational profile are often provided to local permitting authorities so as to indicate whether the project would be EPS compliant.
- Historical emissions or fuel use data can be used to evaluate compliance when existing facilities are purchased. This data is collected by several agencies, including the Environmental Protection Agency and the Energy Information Administration of the U.S. Department of Energy. The Energy Commission can, if necessary, maintain a list of generation facilities that meet the EPS given the data available.

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?

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?

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?

Compliance and Verification – Contract Resources

The following types of contracts (when five years or longer) would come under the emissions performance standard:

- Contracts for energy from specified generation resources (unit-contingent contracts).
- Non-unit contingent contracts for baseload energy from counterparties who own a portfolio of resources.
- Non-unit contingent contracts for baseload energy from counterparties that do not own generation (system power[5])
- "Blended" contracts, in which some of the energy procured under the contract comes from a specific unit or facility and the remainder comes from (a) another specific unit, (b) a portfolio of specified physical resources, or (c) unspecified sources.
- Contracts for capacity with minimum take provisions for energy

Unit-Contingent Contracts

Unit-contingent contracts require the seller to deliver energy in amounts specified in the contract as long as a specific generation unit is operational. If the unit is not operating, the seller is not responsible for delivery. Such contracts usually contain specific provisions about powerplant performance, voiding the contract or calling for penalties if the unit is unavailable more than a specified number of hours.

For unit-contingent contracts for baseload energy, compliance can be handled in a manner similar to that used for existing physical resources. If historical data (generation, fuel use/emissions) is available for an existing facility, compliance for such contracts may be amenable to self-certification. Alternatively, the Energy Commission may be able to maintain a list of generation facilities that meet an EPS based on available data. Existing public data, however, may not be sufficient to allow the Energy Commission to determine whether or not smaller units, out-of-state units, and cogeneration facilities meet the standard.

For unit-contingent contracts with facilities for which a historical record is unavailable (e.g., contracts with facilities under construction or undergoing repowering), data filed

[5] The CPUC report refers to such a contract as providing "unspecified" power.

with permitting authorities can often be used to make a determination of eligibility under the standard.

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?

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?

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?

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?

A variation of a unit-contingent contract is one which specifies a unit but allows the seller to substitute energy from unspecified sources at his discretion. The difficulties created for compliance and verification by such contracts are identical to those created by contracts discussed earlier.

System Power

Contracts for system power, referred to as “unspecified energy” in the CPUC staff report, call for delivery of energy at agreed-upon locations without regard for the source of the energy. The feasibility of a compliance mechanism for system power contracts depends upon how system power is evaluated with respect to the EPS:

(a) If a single emissions value is attributed to all system power, long-term contracts calling for baseload power from unspecified sources will either meet the EPS or fail to do so. If they are allowed under the standard, self-certification for these contracts would appear to be feasible.

(b) If the emissions value for system power varies by geographic region, for example, the eligibility of a given contract could, in theory, be based upon additional information in the contract, including counterparty (e.g., BPA indicates energy from the Northwest), delivery point (a point in SP15 indicates energy from the Southwest), etc. Such markers do not conclusively indicate, however, that the energy delivered under the contract was generated in that region.

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?

Contingent Contracts with Portfolio Owners

A POU may enter into a long-term contract for baseload energy with a counter-party that has a largely standard-compliant portfolio of resources under its control. A contract (a) may not require that the energy be generated by one or more of these resources, or (b) may require that the energy come from this set of resources, not all of which meet the standard.

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?

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?

Blended Contracts

A blended contract is defined here as one in which as-available energy is provided from a specific resource and additional energy is provided from another (dispatchable) source or sources ("firming" resource(s)), so that the total amount of energy sums to the contracted amount.

If the firming resource is specified in the contract, it is easy to assess the emissions footprint of the contract and self-certification is feasible. Assuming that the resource providing as-available energy meets the standard, the firming resource, and thus the contract, will meet the standard if it either (a) is a low-emission plant intended to operate as a baseload facility (e.g., a gas-fired combined cycle) or (b) a peaking unit (i.e., not intended to provide baseload energy). It will not meet the standard if it is a high emission unit designed and intended to provide baseload energy.

If the firming resource is not specified in the contract, then the firming resource is unspecified power. If unspecified power qualifies under the standard, the blended contract meets the standard. If unspecified power does not qualify, the contract may still be deemed to qualify under certain circumstances.

For example, if the unspecified power has a daily peaking profile (as it would be likely to have if the as-available resource is a wind generator). As such, the unspecified component may qualify in isolation under the standard and should thus be deemed to qualify as a component of a blended contract.

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?

Question 5.20

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

Question 5.21

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

Multiple Contracts

The CPUC may determine that multiple short term contracts of less than five years for the same resource violate the statute.

> *“…the [regulation] should not create incentives for LSEs to avoid the substantive standard simply through contractual “gaming” – that is, by entering into multiple smaller contracts, each of which may be below the jurisdictional thresholds, but which together amount to a significant long-term commitment of LSE resources. To that end, staff recommends that a series of related contracts with the same supplier, likely resource, or known facility, or a series of related or similar contracts with separate sources should be considered as a single commitment in size, capacity factor, and duration* (Final Workshop Report, p. 25)*.”*

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?

Chapter 6: Enforcement Options

SB 1368 provides the Energy Commission with the authority to enforce compliance with the EPS by POUs but does not specify enforcement mechanisms. (Pub. Utilities Code §8341(c)(1).) Some stakeholders have argued that the Energy Commission does not need to adopt enforcement mechanisms because POUs, by their very nature, can be trusted to comply with any requirements established by the Energy Commission.

This section does not challenge the POU's intent to comply. It examines the possible procedures necessary for the Energy Commission to enforce compliance with the EPS in light of the main compliance determination approaches discussed in Chapter 5: prior versus post review of power purchase contracts and "new ownership investments." The Energy Commission's method for enforcing the greenhouse gases emission performance standard depends upon the compliance or verification mechanism ultimately adopted and the investment mechanism being addressed. The issues surrounding enforcement are examined below for four potential scenarios.

Question 6.1

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

Prior Review of Contracts

Under a scenario where POUs obtain approval of their contracts before they are entered into, one option for enforcement (where a contract is deemed non-compliant) would be for the Energy Commission to instruct the POU that they are not allowed to enter into that contract. This determination could be made using the existing Complaints and Investigations process outlined in the California Code of Regulations, title 20, section 1230 et seq., or could be made under a new tailor-made process for SB 1368 compliance determinations.

Another option would be to use an Order to Show Cause to require a POU to appear before the Energy Commission and explain why an enforcement action should not be taken. If the POU persisted despite an Energy Commission determination of noncompliance, then one enforcement option would be for the Energy Commission to seek judicial enforcement; most likely in the form of a permanent injunction.

Question 6.2

Are there any other options for enforcement under this scenario?

Prior Review of "New Ownership Investments"

Under a scenario that has the POUs obtaining prior approval for new ownership investments in baseload generation, one enforcement option would be for the Energy Commission to declare the proposed investment noncompliant (in the manners discussed above), and instruct the POU that they are prohibited under SB 1368 from making that investment. If the POU persisted, one option for further enforcement would be for the Energy Commission to seek judicial enforcement.

Question 6.3

Are there any other options for enforcement under this scenario?

Review of Executed Contracts

Enforcement becomes more complicated if Energy Commission compliance review occurs after contracts have already been executed. Enforcement to deter or correct noncompliance under such a scenario may work best by employing two different measures: a penalty measure and a corrective measure. A penalty measure might reduce the likelihood that a POU would risk entering into a noncompliant contract if the penalty was of sufficient weight to act as a deterrent. It is unclear what form this penalty could take. Monetary penalties have not been specifically provided for under SB 1368 and there does not appear to be independent authority under the Warren-Alquist Act to put them in place for this purpose. One possibility would be to require any POU determined to have entered into a noncompliant contract to thereafter undergo prior review of all contracts.

Questions 6.4

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

Once noncompliance is detected it should be quickly corrected and the POU brought back into compliance with SB 1368 and supporting regulations. One option would be to require the POU to cancel the noncompliant contract. The POUs have stated that this may not be an easy or quick task. For due process purposes, they would possibly have to allow the contracting facility time to correct the non-conformance with the EPS. It is unclear whether this potential requirement could be removed with a contract provision allowing the POU automatic termination if the subject facility is found not to comply with the EPS. Even if a POU could legally terminate a contract, doing so may not be practical for reliability reasons. It could take some time to find another source of electricity to replace the noncompliant source.

Question 6.5

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

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?"

Review of Completed "Investment" Transactions

As in after-the-fact review of contracts, enforcement of the EPS after a new ownership investment has already been made can be complicated. As discussed above, instituting a penalty might be useful in deterring noncompliant investments. If such deterrence should fail, however, corrective action would be required. In order for the noncompliance to be corrected, either the facility would have to be made compliant (reduce its emissions to the standard) or the POU would have to somehow retrieve its investment. Parties have argued, however, that once an investment is made in a noncompliant facility the damage has been done and no action could fully correct the harm caused.

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?

APPENDIX

BILL NUMBER: SB 1368 ENROLLED
BILL TEXT

PASSED THE SENATE AUGUST 31, 2006
PASSED THE ASSEMBLY AUGUST 30, 2006
AMENDED IN ASSEMBLY AUGUST 30, 2006
AMENDED IN ASSEMBLY AUGUST 24, 2006
AMENDED IN ASSEMBLY AUGUST 21, 2006
AMENDED IN ASSEMBLY AUGUST 7, 2006
AMENDED IN ASSEMBLY JUNE 22, 2006
AMENDED IN SENATE APRIL 24, 2006

INTRODUCED BY Senator Perata
(Coauthor: Assembly Member Levine)

FEBRUARY 21, 2006

An act to add Chapter 3 (commencing with Section 8340) to Division 4.1 of the Public Utilities Code, relating to electricity.

LEGISLATIVE COUNSEL'S DIGEST

SB 1368, Perata Electricity: emissions of greenhouse gases.

(1) Under existing law, the Public Utilities Commission (PUC) has regulatory authority over public utilities, including electrical corporations. Existing law authorizes the PUC to establish rules for all public utilities, and the Legislature has established procedures for rulemaking proceedings before the PUC. Existing law requires the PUC to review and adopt a procurement plan and a renewable energy procurement plan for each electrical corporation pursuant to the California Renewables Portfolio Standard Program.

Existing law requires the State Energy Resources Conservation and Development Commission (Energy Commission) to certify eligible renewable energy resources, to design and implement an accounting system to verify compliance with the renewables portfolio standard by retail sellers, and to allocate and award supplemental energy payments to cover the above-market costs of electricity generated by eligible renewable energy resources.

Under existing law the governing board of a local publicly owned electric utility is responsible for implementing and enforcing a renewables portfolio standard that recognizes the intent of the Legislature to encourage renewable resources, while taking into consideration the effect of the standard on rates, reliability, and financial resources and the goal of environmental improvement. Existing law requires the governing board of a local publicly owned electric utility to report certain information relative to renewable energy resources to its customers.

Existing law defines an "electric service provider" as an entity that offers electrical service to customers within the service territory of an electrical corporation, excluding electrical corporations, local publicly owned electric utilities, and certain cogenerators. Provisions of the existing Public Utilities Act restructuring the electrical services industry require that electric service providers register with the PUC and require the PUC to authorize and facilitate direct transactions between electric service providers and retail end-use customers. However, other existing law suspends the right of retail end-use customers other than community aggregators, to acquire service through a direct transaction, until the Department of Water Resources no longer supplies electricity under that law.

Existing law defines a "community choice aggregator" and authorizes customers to aggregate their electric loads as members of their local community with community choice aggregators.

The existing restructuring of the electrical industry within the Public Utilities Act provides for the establishment of an Independent System Operator (ISO) as a nonprofit public benefit corporation. Existing law requires the ISO to ensure efficient use and reliable operation of the transmission grid consistent with achieving planning and operating reserve criteria no less stringent than those established by the Western Electricity Coordinating Council and the American Electric Reliability Council.

Under existing law, the State Air Resources Board, the Energy Commission, and the California Climate Action Registry all have responsibilities with respect to the control of emissions of greenhouse gases, as defined, and the Secretary for Environmental Protection is required to coordinate emission reductions of greenhouse gases and climate change activity in state government.

This bill would prohibit any load-serving entity, as defined, and any local publicly owned electric utility, from entering into a long-term financial commitment, as defined, unless any baseload generation, as defined, complies with a greenhouse gases emission performance standard. The bill would require the PUC, by February 1, 2007, through a rulemaking proceeding and in consultation with the Energy Commission and the State Air Resources Board, to establish a greenhouse gases emission performance standard for all baseload generation of load-serving entities. The bill would require the Energy Commission, by June 30, 2007, at a duly noticed public hearing and in consultation with the PUC and the State Air Resources Board, to establish a greenhouse gases emission performance standard for all baseload generation of local publicly owned electric utilities. The bill would require that the greenhouse gases emission performance standard not exceed the rate of emissions of greenhouse gases for combined-cycle natural gas, as defined, baseload generation. The bill would prohibit the PUC from approving any long-term financial commitment by an electrical corporation unless any baseload generation supplied under the long-term commitment complies with the greenhouse gases emission performance standard. The bill would authorize the PUC to review any long-term financial commitment proposed to be entered into by an electric service provider or community choice aggregator in order to enforce the bill's requirements. The bill would require the PUC to adopt rules to enforce these requirements for load-serving entities and would require the PUC to adopt procedures, for all load-serving entities, to verify the emissions of greenhouse gases from any baseload generation supplied under a contract subject to the greenhouse gases emission performance standard. The bill would require the PUC, through a rulemaking proceeding and in consultation with the Energy

Commission and the State Air Resources Control Board, to reevaluate and continue, modify, or replace the greenhouse gases emissions performance standard when an enforceable greenhouse gases emissions limit is established and in operation, that is applicable to load-serving entities.

The bill would require the Energy Commission to adopt regulations for the enforcement of the greenhouse gases emission performance standard with respect to a local publicly owned electric utility. The bill would require the Energy Commission, in a duly noticed public hearing and in consultation with the PUC and the State Air Resources Board, to reevaluate and continue, modify, or replace the greenhouse gases emission performance standard when an enforceable greenhouse gases emissions limit is established and in operation, that is applicable to local publicly owned electric utilities.

(2) Under existing law, a violation of the Public Utilities Act or an order or direction of the commission is a crime.

Because certain of the provisions of this bill are within the act and require action by the commission to implement its requirements, a violation of these provisions would impose a state-mandated local program by creating a new crime.

(3) The California Constitution requires the state to reimburse local agencies and school districts for certain costs mandated by the state. Statutory provisions establish procedures for making that reimbursement.

This bill would provide that no reimbursement is required by this act for a specified reason.

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

SECTION 1. The Legislature finds and declares all of the following:

(a) Global warming will have serious adverse consequences on the economy, health, and environment of California.

(b) The Governor, in Executive Order S-3-05, has called for the reduction of California's emission of greenhouse gases to 1990 levels by 2020.

(c) Over the past three decades, the state has taken significant strides towards implementing an environmentally and economically sound energy policy through reliance on energy efficiency, conservation, and renewable energy resources in order to promote a sustainable energy future that ensures an adequate and reliable energy supply at reasonable and stable prices.

(d) To the extent energy efficiency and renewable resources are unable to satisfy increasing energy and capacity needs, the Energy Action Plan II establishes a policy that the state will rely on clean and efficient fossil fuel fired generation and will "encourage the development of cost-effective, highly-efficient, and environmentally-sound supply resources to provide reliability and consistency with the state's energy priorities."

(e) California's investor-owned electric utilities currently have long-term procurement plans that include proposals for making new long-term financial commitments to electrical generating resources over the next decade, which will generate electricity while producing emissions of greenhouse gases for the next 30 years or longer. New long-term financial commitments to zero- or low-carbon generating resources should be encouraged.

(f) The Public Utilities Commission (PUC) and State Energy Resources Conservation and Development Commission (Energy Commission) both have concluded, and the Legislature finds, that federal regulation of emissions of greenhouse gases is likely during this decisionmaking timeframe.

(g) It is vital to ensure all electricity load-serving entities internalize the significant and underrecognized cost of emissions recognized by the PUC with respect to the investor-owned electric utilities, and to reduce California's exposure to costs associated with future federal regulation of these emissions.

(h) The establishment of a policy to reduce emissions of greenhouse gases, including an emissions performance standard for all procurement of electricity by load-serving entities, is a logical and necessary step to meet the goals of the Energy Action Plan II and the Governor's goals for reduction of emissions of greenhouse gases.

(i) A greenhouse gases emission performance standard for new long-term financial commitments to electrical generating resources will reduce potential financial risk to California consumers for future pollution-control costs.

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

(k) In order to have any meaningful impact on climate change, the Governor's goals for reducing emissions of greenhouse gases must be applied to the state's electricity consumption, not just the state's electricity production.

(l) The 2005 Integrated Energy Policy Report adopted by the Energy Commission recommends that any greenhouse gases emission performance standard for utility procurement of baseload generation be set no lower than levels achieved by a new combined-cycle natural gas turbine.

(m) As the largest electricity consumer in the region, California has an obligation to provide clear guidance on performance standards for procurement of electricity by load-serving entities.

SEC. 2. Chapter 3 (commencing with Section 8340) is added to Division 4.1 of the Public Utilities Code, to read:

CHAPTER 3. Greenhouse Gases Emission Performance Standard for Baseload Electrical Generating Resources

8340. For purposes of this chapter, the following terms have the following meanings:

(a) "Baseload generation" means electricity generation from a powerplant that is designed and intended to provide electricity at an annualized plant capacity factor of at least 60 percent.

(b) "Combined-cycle natural gas" with respect to a powerplant means the powerplant employs a combination of one or more gas turbines and steam turbines in which electricity is produced in the steam turbine from otherwise lost waste heat exiting from one or more of the gas turbines.

(c) "Community choice aggregator" means a "community choice aggregator" as defined in Section 331.1.

(d) "Electrical corporation" means an "electrical corporation" as defined in Section 218.

(e) "Electric service provider" means an "electric service provider" as defined in Section 218.3, but does not include corporations or persons employing cogeneration technology or producing electricity from other than a conventional power source consistent with subdivision (b) of Section 218.

(f) "Energy Commission" means the State Energy Resources Conservation and Development Commission.

(g) "Greenhouse gases" means those gases listed in subdivision (h) of Section 42801.1 of the Health and Safety Code.

(h) "Load-serving entity" means every electrical corporation, electric service provider, or community choice aggregator serving end-use customers in the state.

(i) "Local publicly owned electric utility" means a "local publicly owned electric utility" as defined in Section 9604.

(j) "Long-term financial commitment" means either a new ownership investment in baseload generation or a new or renewed contract with a term of five or more years, which includes procurement of baseload generation.

(k) "Output-based methodology" means a greenhouse gases emission performance standard that is expressed in pounds of greenhouse gases emitted per megawatthour and factoring in the useful thermal energy employed for purposes other than the generation of electricity.

(l) "Plant capacity factor" means the ratio of the electricity produced during a given time period, measured in kilowatthours, to the electricity the unit could have produced if it had been operated at its rated capacity during that period, expressed in kilowatthours.

(m) "Powerplant" means a facility for the generation of electricity, and includes one or more generating units at the same location.

(n) "Zero- or low-carbon generating resource" means an electrical generating resource that will generate electricity while producing emissions of greenhouse gases at a rate substantially below the greenhouse gas emission performance standard, as determined by the commission.

8341. (a) No load-serving entity or local publicly owned electric utility may enter into a long-term financial commitment unless any baseload generation supplied under the long-term financial commitment complies with the greenhouse gases emission performance standard established by the commission, pursuant to subdivision (d), for a load-serving entity, or by the Energy Commission, pursuant to subdivision (e), for a local publicly owned electric utility.

(b) (1) The commission shall not approve a long-term financial commitment by an electrical corporation unless any baseload generation supplied under the long-term financial commitment complies with the greenhouse gases emission performance standard established by the commission pursuant to subdivision (d).

(2) The commission may, in order to enforce the requirements of this section, review any long-term financial commitment proposed to be entered into by an electric service provider or a community choice aggregator.

(3) The commission shall adopt rules to enforce the requirements of this section, for load-serving entities. The commission shall adopt procedures, for all load-serving entities, to verify the emissions of greenhouse gases from any baseload generation supplied

under a contract subject to the greenhouse gases emission performance standard to ensure compliance with the standard.

(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.

(5) Costs incurred by an electrical corporation to comply with this section, including those costs incurred for electricity purchase agreements that are approved by the commission that comply with the greenhouse gases emission performance standard, are to be treated as procurement costs incurred pursuant to an approved procurement plan and the commission shall ensure timely cost recovery of those costs pursuant to paragraph (3) of subdivision (d) of Section 454.5.

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

(c) (1) The Energy Commission shall adopt regulations for the enforcement of this chapter with respect to a local publicly owned electric utility.

(2) The Energy Commission may, in order to ensure compliance with the greenhouse gases emission performance standard by local publicly owned electric utilities, apply the procedures adopted by the commission to verify the emissions of greenhouse gases from baseload generation pursuant to subdivision (b).

(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 for the operation of the powerplant, any procurement approval decision for the load-serving entity, and any other matter the Energy Commission determines is relevant under the circumstances.

(d) (1) On or before February 1, 2007, the commission, through a rulemaking proceeding, and in consultation with the Energy Commission and the State Air Resources Board, shall establish a greenhouse gases emission performance standard for all baseload generation of load-serving entities, at a rate of emissions of greenhouse gases that is no higher than the rate of emissions of greenhouse gases for combined-cycle natural gas baseload generation. Enforcement of the greenhouse gases emission performance standard shall begin immediately upon the establishment of the standard. All combined-cycle natural gas powerplants that are in operation, or that have an Energy Commission final permit decision to operate as of June 30, 2007, shall be deemed to be in compliance with the greenhouse gases emission performance standard.

(2) In determining the rate of emissions of greenhouse gases for baseload generation, the commission shall include the net emissions resulting from the production of electricity by the baseload generation.

(3) The commission shall establish an output-based methodology to ensure that the calculation of emissions of greenhouse gases for cogeneration recognizes the total usable energy output of the process, and includes all greenhouse gases emitted by the facility in the production of both electrical and thermal energy.

(4) In calculating the emissions of greenhouse gases by facilities generating electricity from biomass, biogas, or landfill gas energy, the commission shall consider net emissions from the process of growing, processing, and generating the electricity from the fuel source.

(5) 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.

(6) In adopting and implementing the greenhouse gases emission performance standard, the commission, in consultation with the Independent System Operator shall consider the effects of the standard on system reliability and overall costs to electricity customers.

(7) In developing and implementing the greenhouse gases emission performance standard, the commission shall address long-term purchases of electricity from unspecified sources in a manner consistent with this chapter.

(8) In developing and implementing the greenhouse gases emission performance standard, the commission shall consider and act in a manner consistent with any rules adopted pursuant to Section 824a-3 of Title 16 of the United States Code.

(9) An electrical corporation that provides electric service to 75,000 or fewer retail end-use customers in California may file with the commission a proposal for alternative compliance with this section, which the commission may accept upon a showing by the electrical corporation of both of the following:

(A) A majority of the electrical corporation's retail end-use customers for electric service are located outside of California.

(B) The emissions of greenhouse gases to generate electricity for the retail end-use customers of the electrical corporation are subject to a review by the utility regulatory commission of at least one other state in which the electrical corporation provides regulated retail electric service.

(e) (1) On or before June 30, 2007, the Energy Commission, at a duly noticed public hearing and in consultation with the commission and the State Air Resources Board, shall establish a greenhouse gases emission performance standard for all baseload generation of local publicly owned electric utilities at a rate of emissions of greenhouse gases that is no higher than the rate of emissions of greenhouse gases for combined-cycle natural gas baseload generation. The greenhouse gases emission performance standard established by the

Energy Commission for local publicly owned electric utilities shall be consistent with the standard adopted by the commission for load-serving entities. Enforcement of the greenhouse gases emission performance standard shall begin immediately upon the establishment of the standard. All combined-cycle natural gas powerplants that are in operation, or that have an Energy Commission final permit decision to operate as of June 30, 2007, shall be deemed to be in compliance with the greenhouse gases emission performance standard.

(2) The greenhouse gases emission performance standard shall be adopted by regulation pursuant to the Administrative Procedure Act (Chapter 3.5 (commencing with Section 11340) of Part 1 of Division 3 of Title 2 of the Government Code).

(3) In determining the rate of emissions of greenhouse gases for baseload generation, the Energy Commission shall include the net emissions resulting from the production of electricity by the baseload generation.

(4) The Energy Commission shall establish an output-based methodology to ensure that the calculation of emissions of greenhouse gases for cogeneration recognizes the total usable energy output of the process, and includes all greenhouse gas emitted by the facility in the production of both electrical and thermal energy.

(5) 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.

(6) 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 from the powerplant.

(7) In adopting and implementing the greenhouse gases emission performance standard, the Energy Commission, in consultation with the Independent System Operator, shall consider the effects of the standard on system reliability and overall costs to electricity customers.

(8) In developing and implementing the greenhouse gases emission performance standard, the Energy Commission shall address long-term purchases of electricity from unspecified sources in a manner consistent with this chapter.

(9) In developing and implementing the greenhouse gases emission performance standard, the Energy Commission shall consider and act in a manner consistent with any rules adopted pursuant to Section 824a-3 of Title 16 of the United States Code.

(f) The Energy Commission, in a duly noticed public hearing and in consultation with the commission and the State Air Resources Board, shall reevaluate and continue, modify, or replace the greenhouse gases emission performance standard when an enforceable greenhouse gases emissions limit is established and in operation, that is applicable to local publicly owned electric utilities.

(g) The commission, through a rulemaking proceeding and in consultation with the Energy Commission and the State Air Resources Board, shall reevaluate and continue, modify, or replace the greenhouse gases emission performance standard when an enforceable greenhouse gases emissions limit is established and in operation, that is applicable to load-serving entities.

SEC. 3.

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