Decision **PROPOSED DECISION OF ALJ SIMON** (Mailed 11/18/2014)

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Continue Implementation and Administration of California Renewables Portfolio Standard Program.	Rulemaking 11-05-005 (Filed May 5, 2011)

DECISION IMPLEMENTING SENATE BILL 1122

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DECISION IMPLEMENTING SENATE BILL 1122

Summary

This decision implements the provisions of Senate Bill (SB) 1122 (Rubio), stats. 2012, ch. 612. This legislation amends Pub. Util. Code § 399.20 (the "feed-in tariff" provisions) of California's renewables portfolio standard (RPS) program to require that investor-owned utilities (IOUs) procure mandated quantities of RPS-eligible generation from facilities using specified types of bioenergy.

This decision:

- Sets the quantities of each type of eligible generation to be procured by each of the three large IOUs, Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDG&E) under the mandate of SB 1122;

- Identifies the required characteristics of each fuel type to be used in RPS-eligible generation under the mandates of SB 1122;

- Extends the exemption of small and multi-jurisdictional utilities from the mandates of Pub. Util. Code § 399.20 generally to the mandates of SB 1122;

- Sets the mechanism for determining the tariff price of generation eligible under SB 1122 within the general framework of the Renewable Market Adjusting Tariff (ReMAT).

    - Sets a statewide "starting price" for SB 1122 generation resources that adjusts by type of bioenergy resource (biogas, dairy, other agricultural, derived from sustainable forest management.)

    - Allows the price to adjust bi-monthly for each bioenergy type.

- Authorizes the Director of Energy Division to explore, in consultation with the parties, the possibility of a mechanism for third-party verification of fuel use to ensure continued eligibility of generation under the mandates of SB 1122;

- Sets an ending date of 60 months from the beginning of the first program period, for the obligation of the IOUs to offer the tariff that includes SB 1122 requirements.

- Requires PG&E, SCE, and SDG&E, within 45 days of the date of this decision, to file and serve a proposed joint tariff and standard contract that include the provisions set out in this decision for generation eligible under SB 1122.

This proceeding remains open.

1. Procedural History

The Order Instituting Rulemaking (OIR) for this proceeding was adopted by the Commission on May 5, 2011. The Scoping Memo and Ruling of assigned Commissioner was issued on July 8, 2011. The implementation of Senate Bill (SB) 1122 (Rubio), Stats. 2012, ch. 612, was added to the scope of this proceeding in the Second Amended Scoping Memo and Ruling of Assigned Commissioner (January 9, 2013).

As part of the process of implementing SB 1122, Energy Division commissioned a report from consultants Black & Veatch titled "Small-Scale Bioenergy: Resource Potential, Costs, and Feed-in Tariff Implementation Assessment." (B&V Report.) A draft version of the B & V report was published in April 2013. Energy Division staff held an informal workshop to discuss the draft report on May 2, 2013. After the workshop, staff solicited informal party comments, submitted to staff and served on the service list of this proceeding in June 2013, but not filed in this proceeding. After being revised in response to the

informal comments, the final version of the B&V Report was published on October 31, 2013.

After considering the B&V Report and the informal comments of the parties, Energy Division staff drafted a Staff Proposal on Implementation of SB 1122 (Staff Proposal). On November 19, 2013, the Administrative Law Judge's (ALJ) Ruling Seeking Comments on Staff Proposal on Implementation of SB 1122 and Accepting Consultant Report into the Record (ALJ Comment Ruling) was issued. Comments were filed on December 20, 2013.[1] Reply comments were filed on January 16, 2014.[2] The ALJ Comment Ruling attached the Staff Proposal as part of the record of this proceeding, and brought into the record of this proceeding the final B&V Report.

2. Discussion

2.1. Introduction

SB 1122 is one of a number of legislative enactments setting up, defining, and refining the parameters of the feed-in tariff (FiT) for the renewables portfolio standard (RPS) program. The initial FiT legislation, Assembly Bill (AB) 1969 (Yee), Stats. 2006, ch. 731, created a program for procurement of renewables portfolio standard (RPS) eligible electricity produced at plants up to

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[1] Comments were filed by Agricultural Energy Consumers Association (AECA); Bioenergy Association of California (BAC); Center for Biological Diversity (CBD); Clean Coalition; Dairy Cares; Environmental Defense Fund; Green Power Institute (GPI); L. Jan Reid; Office of Ratepayer Advocates (ORA); Pacific Forest Trust (Forest Trust); Pacific Gas and Electric Company (PG&E); Phoenix Biomass Energy (Phoenix Energy); Placer County Air Pollution Control District and Sierra Nevada Conservancy, jointly (collectively, Placer APCD); San Diego Gas & Electric Company (SDG&E); Southern California Edison Company (SCE); Sustainable Conservation; and The Utility Reform Network (TURN).

[2] Reply comments were filed by AECA; BAC; California Farm Bureau Federation (Farm Bureau); CBD; Dairy Cares; GPI; ORA; Forest Trust; PG&E; Phoenix Energy; Placer APCD; SDG&E; SCE; Sustainable Conservation; and TURN.

1.5 megawatts (MW) in size at public water and wastewater treatment plants.[3] In Decision (D.) 07-07-027, implementing AB 1969, the Commission expanded the FiT to a broader group of utility customers in PG&E and SCE service territories than those specified in AB 1969.

SB 380 (Kehoe), Stats. 2008, ch. 544, amended Section 399.20 to create one tariff that would apply to all utility customers. SB 32 (Negrete McLeod), Stats. 2009, ch. 328, further amended Section 399.20, increasing the eligible project size to 3 MW. SB 2 (1X) (Simitian), Stats. 2011, ch. 1, amended the statute by changing the language used in referring to the "market price of electricity." The Commission implemented these statutory changes through D.12-05-035, D.13-01-041, and D.13-05-034. The tariffs for the FiT, revised in accordance with these decisions, became effective in July 2013.[4]

SB 1122 adds to Section 399.20 a requirement that investor-owned utilities (IOUs)[5] must collectively procure at least 250 MW of RPS-eligible generation from bioenergy generation projects that commence operation on or after June 1, 2013 and meet the criteria set in the statute.[6] The minimum of 250 MW of

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[3] This legislation was codified in Pub. Util. Code § 399.20. All further references to sections are to the Public Utilities Code unless otherwise noted.

[4] The history of the RPS FiT is discussed and explained in D.12-05-035 and D.13-05-034.

[5] In accordance with the authorization in Section 399.20(c), the Commission has previously concluded that IOUs with fewer than 100,000 service connections in California should be removed from the FiT program. (D.12-05-035, as modified by D.13-01-041, Conclusion of Law 38.) Only the three large IOUs (PG&E, SCE, and SDG&E) participate in the FiT program.

[6] Section 399.20(f)(2)-(4). The statute defines "bioenergy" as "biogas and biomass." (Section 399.20(f)(4).)

The text of Section 399.20, as amended by SB 1122, is attached as Appendix A.

bioenergy to be procured is in addition to the statewide 750 MW of RPS-eligible energy already mandated under Sec. 399.20 prior to SB 1122.

SB 1122 also directs that the procurement obligation will be allocated among the three large IOUs according to two criteria. The total MW will be allocated according to each IOU's share of statewide peak demand. The total procurement obligation is also allocated according to different groupings of bioenergy generation sources, as designated in the legislation.[7]

During the legislative consideration of SB 1122, the author's rationale for the new bioenergy mandate was that bioenergy provides resource diversity and environmental benefits, but the FiT as implemented by the Commission at that time did not offer small bioenergy generation resources a fair chance to compete for contracts under the FiT.[8] The statute therefore requires the Commission to order the procurement of bioenergy generation resources, as specified.

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[7] The allocations set forth in Section 399.20(f)(2)(A) are:

- 110 MW for biogas from wastewater treatment, municipal organic waste diversion, food processing, and codigestion;
- 90 MW for dairy and other agricultural bioenergy; and
- 50 MW for bioenergy using byproducts of sustainable forest management.

[8] *See*, e.g., the Author's Statement included in Bill Analysis, Assembly Committee on Utilities and Commerce (June 22, 2012):

> SB 1122 establishes a statewide procurement requirement of 250 MW from small (less than 5 MW) renewable biomass or biogas projects that utilize low-emission technologies from landfills and organic waste diversion facilities, waste water treatment plants, food and agricultural processing facilities, animal waste facilities, and farms. It requires the PUC to allocate the 250 MW among the state's three major IOUs. The PUC's Decision revising the Feed-in Tariff Program ignores market considerations for small renewable biomass or biogas projects and fails to promote diversity in resource technologies. Without differentiating small

Footnote continued on next page

A number of parties identify a wide array of benefits that they assert are associated with some or all of the types of bioenergy resources specified in SB 1122. To the extent that the claimed benefits provide additional information and background about the general area of bioenergy, such comments are helpful to the Commission, the parties, and the public. On the other hand, to the extent that the claimed benefits are advanced as grounds for the Commission to take a particular course in implementing SB 1122, such comments are not relevant. The Legislature considered and balanced possible benefits and possible disadvantages of various bioenergy resources when it enacted SB 1122. This decision is not the place to engage in another evaluation of possible advantages

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> renewable biomass and biogas projects from other renewable distributed generation technologies, opportunities for methane pollution reduction and clean energy generation will not be realized. Unless and until the PUC accounts for benefits to ratepayers and the environment from reducing air pollution and global warming emissions by generating electricity from small renewable biomass and biogas, a separate procurement requirement for these technologies is necessary. As highlighted in a recent report from the California Energy Commission (CEC), California's biopower industry has been stagnant for over twenty years, a time period during which wind and solar have performed strongly. When comparing biopower results in the United States to leading biopower markets around the world like Germany, the contrast is stark. The intent of SB 1122 is to unleash a growth spurt in California's biopower market, like what has been experienced in leading biopower markets around the world.

The Commission takes official notice of the drafting history and legislative history of SB 1122, in accordance with Rule 13.9 of the Commission's Rules of Practice and Procedure. (*See* Quintano v. Mercury Casualty Co. (1995) 11 Cal. 4th 1049, 1062 n 5.) The successive drafts and legislative history of SB 1122 may be accessed at: http://www.leginfo.ca.gov/cgi-bin/postquery?bill_number=sb_1122&sess=PREV&house=B&author=rubio.

and disadvantages of the various bioenergy resources for which SB 1122 supplies an RPS procurement mandate.

2.2. Characterization of Bioenergy Resource Categories

SB 1122 identifies three broad categories of bioenergy resources, which include multiple elements within them. Section 399.20(f)(2)(A) sets out the categories:

i. Biogas from wastewater treatment, municipal organic waste diversion, food processing, and codigestion;
ii. Dairy and other agricultural bioenergy;
iii. Bioenergy using byproducts of sustainable forest management.

In order for the Commission to implement and administer the bioenergy FiT mandated by SB 1122 in an efficient, fair, and transparent way, it is necessary to have clear and specific characterizations of each element of the categories of bioenergy resources set out in the statute. The following sections of this decision carry out that task.

It is important to note that the characterizations and definitions developed below and adopted in this decision are solely for the purposes of implementing the RPS procurement obligation of 250 MW of RPS-eligible generation from bioenergy resources, as specified by SB 1122. In adopting these characterizations, the Commission is acting only to administer the bioenergy FiT required by SB 1122. Nothing in this decision is intended to apply to any program or requirement other than those specified in Section 399.20, and related administrative requirements of the RPS program.

2.2.1. Biogas

The first category consists of biogas, which may be derived from the four sources listed in the statute. "Biogas" is not, however, a self-defining term. Although there is wide agreement that biogas is derived from organic sources, it is necessary to be more specific for the purposes of implementing SB 1122.

The Staff Proposal uses the definition of "biogas" found in the California Energy Commission (CEC), *Renewables Portfolio Standard Eligibility Guidebook* (7th ed. April 2013) (*Eligibility Guidebook*).[9] As it appears in the Glossary of Terms, the term biogas "includes digester gas, landfill gas, and any gas derived from an eligible biomass feedstock." (*Eligibility Guidebook* at 116.)

This proposal is supported by Phoenix Energy, BAC, and Farm Bureau. GPI opposes the proposed addition, on the grounds that gasification of solid biomass is a different kind of energy source from biogas.

The Staff Proposal's use of the definition in the Glossary of Terms of the CEC's *Eligibility Guidebook* as the source for a definition of "biogas" for SB 1122 purposes is sound. It advances the important value of consistency of terminology within the RPS program. We therefore adopt the definition of "biogas" as "including digester gas, landfill gas, and any gas derived from a feedstock eligible under the California renewables portfolio standard," for purposes of implementing SB 1122.

Our use of this definition is, however, limited to the context of SB 1122. We do not adopt this definition of "biogas" for the purpose of determining eligibility for the RPS program as a whole, a task committed by statute to the

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[9] The *Eligibility Guidebook* may be found at http://www.energy.ca.gov/renewables/documents/index.html#rps.

CEC.[10] We use this definition simply as part of the process of identifying generation facilities that may participate in the bioenergy FiT procurement process.[11] Many facilities may be RPS-eligible, but some of them will not meet the requirements for participation in the bioenergy FiT under SB 1122 for any of a number of reasons.

A significant reason that an RPS-eligible facility using biogas generation may not be eligible to participate in the bioenergy FiT under SB 1122 is that the feedstock used is not one of the four listed in SB 1122 for the biogas category: wastewater treatment, municipal organic waste diversion, food processing, and codigestion. An example is landfill gas. This source is included in the language of our "biogas" definition for purposes of implementing SB 1122; it is considered to be RPS-eligible by the CEC; but it is not eligible for the bioenergy FiT because it is not on the list of resources set out in SB 1122 for the biogas category.

We now turn in more detail to the resources listed in the first category for participation in the bioenergy FiT.

2.2.1.1. Wastewater Treatment

The Staff Proposal identifies Water Code § 13625(b) as the appropriate source for the definition of a facility that is a source of "biogas from wastewater treatment."[16] No party objects to this proposal. The proposal provides a clear and reasonable definition. It is adopted.

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[10] *See* Section 399.13.

[11] In contrast to requiring use of the definition of "commercial operations date," found in the CEC Eligibility Guidebook at the time a generation facility submits its program participation request (*see* section 2.5.1, below), the definition of "biogas" adopted here applies throughout the entire bioenergy FiT program mandated by SB 1122.

[16] Water Code § 13625(b) provides:

2.2.1.2. Municipal Organic Waste Diversion

The Staff Proposal notes that the term "municipal organic waste diversion" appears to be unique to Section 399.20 among California statutory provisions. Parties have not cited any definition of the term in the legislative history of SB 1122, and we have found none.

In this circumstance, the Staff Proposal reasonably turns for authoritative guidance in constructing a workable understanding of this term to the regulations promulgated by the California Integrated Waste Management Board (IWMB) on "Planning Guidelines and Procedures for Preparing and Revising Countywide Integrated Waste Management Plans," 14 CCR § 18720 *et seq*.

The Staff Proposal blends the definitions of three terms used in the IWMB regulations to develop a definition for purposes of implementing SB 1122: "municipal solid waste;"[18] "organic waste;"[19] and "waste diversion."[20] The

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[18] 14 CCR § 17720(a)(40) provides:

> "Municipal solid waste" or "MSW" means all solid wastes generated by residential, commercial, and industrial sources, and all solid waste generated at construction and demolition sites, at food-processing facilities, and at treatment works for water and waste water, which are collected and transported under the authorization of a jurisdiction or are self-hauled. Municipal solid waste does not include agricultural crop residues (SIC Codes 071 through 0724, 0751), animal manures (SIC Code 0751), mining waste and fuel extraction waste (SIC Codes 101 through 1499), forestry wastes (SIC Codes 081 through 0851, 2411 and 2421), and ash from industrial boilers, furnaces and incinerators.

[19] 14 CCR § 18720(a)(47) provides:

> "Organic waste" means solid wastes originated from living organisms and their metabolic waste products, and from petroleum, which contain naturally produced organic compounds, and which are biologically decomposable by microbial and fungal action into the constituent compounds of water, carbon dioxide, and other simpler organic compounds.

blended definition of "biogas from organic waste diversion" developed in the Staff Proposal is as follows:

> Biogas that is generated from:
>
> (1) A diversion of organic solid wastes, in accordance with all applicable federal, state and local requirements, from disposal at solid waste landfills or transformation facilities; and,
>
> (2) Where the organic solid wastes originated from living organisms and their metabolic waste products which contain naturally produced organic compounds, and which are biologically decomposable by microbial and fungal action into the constituent compounds of water, carbon dioxide, and other simpler organic compounds; and,
>
> (3) Where the organic solid wastes were generated by residential, commercial, and industrial sources, or were generated at construction and demolition sites, at food-processing facilities, or at treatment works for water and waste water, and which were collected and transported under the authorization of a jurisdiction or were self- hauled.

The Staff Proposal additionally provides that all three characteristics must be present in order for a source to comply with the definition.

No party objects to the proposed definition. Although complex, the proposed definition is based on the regulations of an authoritative state agency and can be applied in practice by this Commission. It is therefore adopted.

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[20] 14 CCR § 18720(a)(80) provides:

> "Waste diversion" means to divert solid waste, in accordance with all applicable federal, state and local requirements, from disposal at solid waste landfills or transformation facilities through source reduction, recycling or composting.

2.2.1.3. Food Processing

The Staff Proposal states that "food processing" is another term that is not found in any other California statute. The parties have not cited any definition of that term in the legislative history of SB 1122, and we have found none. The Staff Proposal reasonably interprets this term as referring to the transformation of agricultural ingredients into food. The Staff Proposal also reasonably suggests that "food processing" should be interpreted in a way that clearly distinguishes it from "other agricultural" in the second statutory category.

The Staff Proposal looks to the North American Industry Classification System (NAICS) as an authoritative source to use in defining "food processing" for purposes of implementing SB 1122.[21] In particular, the Staff Proposal refers to Title 311 of NAICS, which enumerates economic activities classified within the "food manufacturing" industries.[22] The Staff Proposal simply relies on the Title 311 enumeration to propose that "biogas from food processing" be interpreted to mean biogas that is generated from the "food manufacturing" activities listed in Title 311 of NAICS.

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[21] The U.S. Census Bureau describes NAICS as:

> the standard used by Federal statistical agencies in classifying business establishments for the purpose of collecting, analyzing, and publishing statistical data related to the U.S. business economy. NAICS was developed under the auspices of the Office of Management and Budget (OMB), and adopted in 1997 to replace the Standard Industrial Classification (SIC) system. It was developed jointly by the U.S. Economic Classification Policy Committee (ECPC), Statistics Canada , and Mexico's Instituto Nacional de Estadistica y Geografia , to allow for a high level of comparability in business statistics among the North American countries. Available at: www.census.gov/naics/

[22] This list may be found at: http://www.census.gov/cgi-bin/sssd/naics/naicsrch?chart_code=31&search=2012%20NAICS%20Search

No parties oppose this proposed definition, but AECA suggests that the definition should be made fuller and more specific. Drawing on the Food and Agriculture Code for a definition of "processor," AECA develops a more expansive definition:

> . . . Utilizing waste, residue or by-products of food processing or manufacturing facilities, consistent with activities described as "food manufacturing" in Title 311 of the North American Industry Classification System (NAICS). Food processing and manufacturing includes, but is not limited to canning, cooking, roasting, chopping, slicing, cutting, peeling, juicing, milling, fermenting or other processing or manufacturing that changes the form of raw agricultural ingredients into food, or of food into other forms.[23]

This definition proposed by AECA of "food processing" activities is sufficiently specific that it can be understood by IOUs and market participants and administered by the Commission. It is a reasonable approach for purposes of implementing SB 1122 and is adopted.

2.2.1.4. Codigestion

Codigestion is a general term for the anaerobic digestion of multiple feedstocks. In order to distinguish "codigestion" as a category from "dairy" bioenergy, the Staff Proposal (at 20) characterizes biogas from codigestion as being produced:

> . . . from the anaerobic digestion of multiple biodegradable substrates or feedstocks, provided that dairy cattle manure constitutes less than 50% of the facility's fuel source.

[23] AECA Comments at 9.

Several parties object to including a fixed percentage of dairy manure in the codigestion category.[24] They assert that it is confusing and unnecessary to set a percentage of dairy manure because codigestion is already generally understood in the industry to cover anaerobic digestion with multiple organic feedstocks, regardless of the percentage composition of substrate. They argue that the Staff Proposal's definition makes it more difficult, rather than easier, to distinguish between codigestion and dairy digesters as processes for SB 1122 purposes.

AECA proposes a definition of codigestion that removes the percentage of dairy manure and provides a nonexhaustive list of examples:

> . . . [produced] from anaerobic digestion of multiple biodegradable substrates or feedstocks, including but not limited to biosolids, wastewater, animal waste, food scraps, fats, oils, and grease (FOG) or any other suitable organic material.[25]

This definition proposed by AECA is in line with the understanding of codigestion in the industry and in California regulatory practice.[26] It reasonably differentiates codigestion from dairy digestion projects and is administratively simpler than the Staff Proposal, which would have required quantitative analysis

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[24] They include AECA, Dairy Cares, and Sustainable Conservation.

[25] AECA Comments at 11. The substitution of "produced" for AECA's "generated" is intended to eliminate the chance of confusion between the process that produces the biogas, and the process of generating electricity using the biogas as fuel.

[26] AECA cites the Dairy Digester and Co-Digester Final Programmatic Environmental Impact Report, prepared for the Central Valley Regional Water Quality Control Board in 2010, on the difference between codigestion and dairy manure digestion projects. This report may be found at http://www.waterboards.ca.gov/rwqcb5/water_issues/dairies/dairy_program_regs_requirements/dairy_peir_final_cert.pdf.

of the feedstocks used in codigestion projects. The definition proposed by AECA, as modified above, is adopted.

2.2.1.5. Fuel Source Content

Because feedstocks for bioenergy projects are waste products from other processes, it is necessary to establish a method of determining whether a bioenergy generation project is using feedstock that complies with statutory requirements. As the Staff Proposal notes and parties agree, the most basic element of compliance is establishing and maintaining RPS eligibility of the generation facility and the fuel source. The Staff Proposal that 100% of the fuel source used for a biogas generation project must be RPS-eligible is adopted.

The Staff Proposal also includes a general requirement that at least 80% of the fuel source be of the type designated by the generator as the fuel source, measured on an annual basis. Most parties agree.[27] This proposal is adopted, with the exception of the "dairy" category, for which no mixture, beyond a de minimis amount, of other fuel sources with dairy manure is permissible. (See section 2.2.2.1., below.) If the generator chooses to use up to 20% fuel not of the designated type, it must use fuel that complies with the requirements set out in this decision for eligibility under SB 1122, in any of the technology categories. This will give generators the opportunity to continue to produce electricity if there are unanticipated variations in fuel availability, without allowing a “bid and switch” strategy in which a generation facility has its bid accepted and takes a tariff in one technology category, but in fact uses predominately fuel of another type.

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[27] These include AECA, Farm Bureau, Forest Trust, PG&E, Reid, and SCE.

The related issues of verification of fuel source for this and the other categories of bioenergy generation technology are discussed in section 2.2.4., below.

2.2.2. Dairy and Other Agricultural Bioenergy

As the Staff Proposal points out, this second broad category of bioenergy resources does not specify that it applies only to biogas, as did the first, or only to biomass. The use of "bioenergy," which Section 399.20(f)(4) defines as biogas and biomass, as the heading for the category makes this clear. Although, as GPI points out, it might have been possible simply to use the bioenergy technology categories "biogas" and "biomass," SB 1122 does not do so. Rather, the statute uses the three categories set out in Section 399.20(f)(2)(A), which make rough groupings of the source from which the bioenergy is derived. Therefore, while the difference between the use of biomass or biogas for fuel may be important for a particular technology or facility, it is not relevant to the characterization of this category for SB 1122 implementation.

2.2.2.1. Dairy

The Staff Proposal and the parties commenting on dairy issues[28] agree that the "dairy" portion of the "dairy and other agricultural bioenergy" category encompasses the use of dairy cattle manure as the substrate for anaerobic digestion. The Staff Proposal characterizes this subcategory as requiring that at least 80% of the substrate be dairy manure.

However, as discussed in section 2.2.1.4., above, it is generally understood in the bioenergy industry that dairy cattle manure should be the exclusive

[28] AECA, Dairy Cares, GPI, and Sustainable Conservation are the principal groups addressing dairy issues.

substrate of digestion categorized as "dairy." Consistent with the Commission's adoption of this standard for the "codigestion" element of the first category, we adopt AECA's definition of the "dairy" element of the second category as "biogas [produced] solely from the anaerobic digestion of dairy waste."[29]

2.2.2.2. Other Agricultural

As the Staff Proposal notes, the term "other agricultural bioenergy" is unique to Section 399.20 in California statutes. The legislative history of SB 1122 provides no discussion of the meaning of the term. Unlike some of the other terms discussed above, parties' comments reveal that this broad term has no generally accepted meaning in the bioenergy industry.

In this circumstance, the Staff Proposal sensibly turns to the Commission's proceedings for guidance. The Staff Proposal refers to a settlement agreement in SCE's 2011 application on marginal cost, revenue allocation, and rate design, approved by the Commission in D.13-03-031. That settlement includes a definition of "agricultural power service" that characterizes customers' facilities eligible to receive such service. The Staff Proposal uses that definition as the basis of its proposed definition of "other agricultural bioenergy":

> Biomass or biogas that is generated by a customer on the same premises where the customer produces agricultural or horticultural products, including poultry or livestock, as well as biomass or biogas that is generated on the premises by: (1) packing houses that pack only whole fruits or whole vegetables, and associated cold storage on the same premises as the packing houses; (2) cotton gins; and (3) nut hulling and shelling operations.

[29] AECA Comments at 11.

Phoenix Energy objects to two aspects of the Staff Proposal. First, Phoenix Energy argues that the definition of "agricultural wastes" of the California Integrated Waste Management Board (14 CCR § 18720(a)(1)) is more appropriate:

> "Agricultural wastes" means solid wastes of plant and animal origin, which result from the production and processing of farm or agricultural products, including manures, orchard and vineyard prunings, and crop residues, which are removed from the site of generation for solid waste management.

As AECA and Dairy Cares point out, this definition includes "processing of farm or agricultural products." It therefore does not maintain the distinction between this SB 1122 category and the "food processing" element of the first category. For this reason, the suggestion of Phoenix Energy is rejected.

Second, Phoenix Energy argues that the Staff Proposal's requirement that the production of biogas or biomass be "on the same premises" as the agricultural operation is too restrictive, preventing agricultural operations in the same area from pooling their waste resources, to be used by one facility. BAC also urges that "the definition of agricultural waste should not limit eligible feedstock to feedstock that is produced on the same premises as the bioenergy facility."[30]

AECA proposes a definition that is based on the same "Agricultural Power Service" definition as the Staff Proposal, but is more detailed and descriptive than the definition in the Staff Proposal.[31] It is supported by Dairy Cares and

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[30] BAC Opening Comments at 8-9.

[31] AECA states that its proposal use elements from both the definition for SCE's customers relied on by the Staff Proposal, and elements from PG&E's definition. In a motion dated February 20, 2014, AECA seeks official notice of the PG&E definition. AECA states that this definition was adopted in D.06-11-030 and is available on PG&E's web site at http://www.pge.com/tariffs/tm2/pdf/ELEC_RULES_1.pdf.

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Sustainable Conservation. AECA proposes that a project under "other agricultural bioenergy"

> . . . is co-located with an agricultural operation and utilizes the waste, residue or by-products of growing crops, raising livestock or growing horticultural products. Agricultural wastes include, but are not limited to, agricultural crop residues; fruits and vegetables; orchard and vineyard removal; and crop tree and vineyard prunings. Agricultural waste also includes waste, residues and by-products from agricultural drying, hulling, shelling and ginning operations as well as fresh fruit and vegetable packing operations.[32]

In its comments, AECA makes clear that the focus of its proposal is to draw a clear distinction between "other agricultural" bioenergy (in the second category), and biogas from "food processing" (in the first category). That is a significant benefit, and argues for adopting the AECA proposed definition. The wording of the proposal is not so clear, however, with respect to whether the phrase "co-located with an agricultural operation" means that the bioenergy project must be on the same premises as the agricultural operation (as the Staff Proposal requires), or whether the bioenergy project may be on premises with agricultural activities, but the source of the feedstock is not restricted to those same premises (as Phoenix Energy requests).

The idea advanced by Phoenix Energy is sound. Allowing the "other agricultural" feedstock to be obtained from complying agricultural sources that are not necessarily on the same premises as the bioenergy generation facility will

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This is an appropriate subject for official notice pursuant to Rule 13.9 of the Commission's Rules of Practice and Procedure. The motion is granted.

[32] AECA Comments at 9.

maximize the opportunities to use "other agricultural" fuel sources in the same general area as feedstock for one facility, as BAC, Farm Bureau, and Phoenix Energy point out. Requiring that the generation facility also be on agricultural premises increases the value of this resource to farmers (and thus increases the likelihood that they would be interested in it). It also reduces the likelihood that the generation facility will be located far from the sources of feedstock, which could introduce the prospect of emissions from long-distance truck transport of feedstock to the generation facility.

We therefore adopt a modified version of the AECA proposal. A project that meets the criteria for the "other agricultural bioenergy" category:

> ... is located on agricultural premises and utilizes the waste, residue or by-products of growing crops, raising livestock or growing horticultural products. Agricultural wastes include, but are not limited to, agricultural crop residues; fruits and vegetables; orchard and vineyard removal; and crop tree and vineyard prunings. Agricultural waste also includes waste, residues and by-products from agricultural drying, hulling, shelling and ginning operations as well as fresh fruit and vegetable packing operations.

2.2.2.3. Fuel Source Content

The general requirement that at least 80% of the fuel source, measured on an annual basis, must be of the type designated by the generator as the fuel source applies to the "other agricultural" category, though not to the "dairy" category, for which no mixture of other fuel sources with dairy manure is permissible. (See sections 2.2.1.4.; 2.2.2.1. above.) If the generator chooses to use up to 20% fuel not of the designated type, it must use fuel that complies with the requirements set out in this decision for eligibility under SB 1122.

The related issues of verification of fuel source eligibility for this and the other categories of bioenergy generation technology are discussed in section 2.2.4., below.

2.2.3. Bioenergy Using Byproducts of Sustainable Forest Management

Like the category of "dairy and other agricultural bioenergy," this category includes both biogas and biomass fuels. The detailed characterization of this third category of bioenergy, however, has engendered substantially more controversy among the parties than the other two. It is therefore important to reiterate that this decision implements an amendment to the feed-in tariff program for procurement of RPS-eligible energy. To the extent that this decision defines terms or characterizes practices, it does so solely in the context of, and for the purpose of, implementing SB 1122; in particular, to implement the statutory procurement allocation of 50 MW of forest-derived bioenergy. No wider applicability of this decision is intended.

The full statutory description of this category, found in Section 399.20(f)(2)(A)(iii), reads:

> For bioenergy using byproducts of sustainable forest management, 50 megawatts. Allocations under this category shall be determined based on the proportion of bioenergy that sustainable forest management providers derive from sustainable forest management in fire threat treatment areas, as designated by the Department of Forestry and Fire Protection.

The controversy among the parties focuses on how to identify "sustainable forest management" for purposes of implementing SB 1122.[33]

As the Staff Proposal notes, the phrase "sustainable forest management" is unique to Section 399.20 in California statutes. The phrase also has no regulatory definition in the California Code of Regulations (CCR).

Indeed, there appears to be no uniquely authoritative definition of sustainable forest management. The Society of American Foresters includes a definition in The Dictionary of Forestry. The first sentence of that definition states: "this evolving concept has several definitions."[34] In its *National Report on Sustainable Forests – 2010*, the U.S. Forest Service uses an approach that is similar to, but not the same as, that in the Dictionary of Forestry. The framework used in the Forest Service report is an internationally developed approach called the Montreal Process Criteria and Indicators.[35]

In response to the absence of available California authority on which a characterization of this category could be constructed, Energy Division staff

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[33] Although some parties have suggested that the second sentence of Section 399.20(F)(2)(A)(iii) requires the use of fire threat treatment areas designated by CAL FIRE as part of the definition of the category of "bioenergy using byproducts of sustainable forest management," a plain reading of the language demonstrates that fire threat treatment areas are relevant to "allocations under this category," not to definitions. (emphasis supplied.) Fire threat treatment areas are therefore discussed in section 2.4.1. below, on allocation of SB 1122 procurement targets.

[34] The definition may be found at http://dictionaryofforestry.org/dict/term/sustainable_forest_management.

[35] This approach is explained in the first chapter of the report, downloadable at http://www.fs.fed.us/research/sustain/docs/national-reports/2010/2010-sustainability-report.pdf.

Both approaches are reproduced in appendices to the CAL FIRE staff white paper, discussed below.

consulted staff of the Department of Forestry and Fire Protection (CAL FIRE). The Staff Proposal reflects information from this interagency staff consultation.[36]

After the Staff Proposal was completed and circulated with the ALJ Comment Ruling, CAL FIRE staff produced a report titled Forest Derived Biomass Supply Eligibility under Section 399.20 of the Public Utilities Code (November 22, 2013) (CAL FIRE staff white paper).[37] Placer APCD filed a motion to submit the CAL FIRE staff white paper in this proceeding. The motion was granted January 15, 2014. In May 2014, Placer APCD sought leave to submit a revised version of the CAL FIRE staff white paper (dated April 29, 2014) into the record in this proceeding. The ALJ granted the request on June 6, 2014, and allowed parties to file and serve comments and reply comments on the revised CAL FIRE staff white paper.[38]

The Commission appreciates the attention and expertise of CAL FIRE staff and the detailed methodology that they have presented in the staff white paper. The Commission's analysis and this decision have benefited from the efforts of CAL FIRE staff.[39]

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[36] Staff Proposal at 25.

[37] In the CAL FIRE staff white paper, CAL FIRE staff state that they engaged in a stakeholder consultation process hosted by the Sierra Nevada Conservancy as part of developing the CAL FIRE staff white paper. The CAL FIRE stakeholder process is part of the process that CAL FIRE staff undertook in preparing the staff white paper. It is not part of the record or process in this proceeding.

[38] Comments were filed on June 20, 2014 by CBD, GPI, Placer APCD, and SDG&E and PG&E (jointly; collectively, SDG&E). Reply comments were filed July 2, 2014 by CBD, GPI, PG&E, and Placer APCD.

[39] Placer APCD asserts that the Commission must defer to CAL FIRE staff in characterizing "byproducts of sustainable forest management." However, as CBD and Forest Trust correctly point out, this position confuses the statutory source for the allocation of MW in Category 3

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Responding to the uncertainty in the definition and understanding of "sustainable forest management," the Staff Proposal does not provide a conceptual definition of the term. Instead, the Staff Proposal lists four types of activities that would support the use of bioenergy feedstock from those activities for generation eligible under the criteria of SB 1122.[40]

The CAL FIRE staff white paper includes a general definition of "sustainable forest management" as well as a detailed discussion of the types of activities that would support eligibility of the fuel source under SB 1122.[41] Some parties, including CBD and GPI, raise objections to elements of the general definition in the CAL FIRE staff white paper. Forest Trust recommends the use of a different standard, based on ideas put forward in the cover memorandum forwarded to Commission staff with the CAL FIRE staff white paper.[42]

(CAL FIRE's fire threat treatment areas) with the authority to characterize the resource category for purposes of implementing SB 1122, which remains with this Commission.

[40] The types of activities in the Staff Proposal (presented in detail at 25-27) are fire threat reduction; fire safe clearance activities; infrastructure clearance projects; and other sustainable forest management activities.

[41] The general definition, set out in the CAL FIRE staff white paper at 4, is:

> Qualifying byproducts from sustainable forest management include materials derived from projects that are conducted to reduce fuels which pose a threat to public and the environment in and around communities as well as projects which can be demonstrated to contribute to restoration of forests, enhance the resilience of forests through reduction in fire threat, contribute to restoration of unique forest habitats or maintain or restores forest biodiversity, productivity and regeneration capacity.

[42] Forest Trust proposes:

> Bioenergy feedstock from forestry operations that reduce uncharacteristic wildfire risk, increase or maintain a structurally complex forest type native to California, and utilize prescriptions that follow historic disturbance patterns, certified and approved by CalFIRE or the USFS

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It is not necessary for this Commission to resolve the issues raised by the CAL FIRE staff white paper definition and the comments on it. The Commission does not need to wade into what is revealed by the record in this proceeding to be a longstanding, complex, and highly technical discussion about how to define the concept of "sustainable forest management." For purposes of implementing SB 1122, it is sufficient to be able to identify, clearly enough to allow compliance with the criteria and meaningful verification of compliance, those activities whose byproducts meet the SB 1122 criterion of "byproducts of sustainable forest management."

With this basic goal in mind, we turn to analysis of the four types of activities identified in the Staff Proposal, and their analogues in the CAL FIRE staff white paper. The Staff Proposal is given below. Additions or deletions put forward in the CAL FIRE staff white paper are shown as underlines or strike-outs, respectively.

2.2.3.1. Fire Threat Reduction

Fire threat reduction. ~~Bioenergy~~ Biomass feedstock which originates from fuel reduction activities identified in a fire plan approved by CAL FIRE or other appropriate state, local or federal agency. Categorical exclusions on federal lands approved under 36 CFR 220.6(e)(6)ii and (12) thru (14).

CBD argues that this element, like the two that follow it, focuses on fire threat reduction activities but does not make any usable connection between those activities and "sustainable forest management." GPI and Placer APCD assert that avoidance of damaging wildfires is one of the benefits of using

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[United States Forest Service] as appropriate. (Forest Trust Comments at 3, 15.)

forest-derived fuels, so characterizations of this category that include concern for fire threat reduction are appropriate.

Without taking a position on any of the many controversies associated with the history, benefits, and costs of fire in the California landscape,[43] it is reasonable for the Commission to conclude that using forest-derived fuels related to reducing the likelihood of damaging wildfires is a legitimate element of the characterization of "byproducts of sustainable forest management" for purposes of implementing SB 1122. The Staff Proposal, with the additions shown above of references to federal lands provided through the expertise of CAL FIRE staff, and the sensible clarification that only "biomass" is at issue, is adopted.

2.2.3.2. Fire Safe Clearance Activities

> **Fire safe clearance activities.** ~~Bioenergy~~ Biomass feedstock originating from fuel reduction activities conducted to comply with Pub. Res. Code Sections 4290 and 4291. This would include ~~bioenergy~~ biomass feedstocks from timber operations conducted in conformance with 14 CCR 1038(c) (150' Fuel Reduction Exemption) as well as projects that fall under 14 CCR 1052.4 (Emergency for Fuel Hazard Reduction), 14 CCR 1051.3-1051.7 (Modified THP [timber harvest plan] for Fuel Hazard Reduction), and 14 CCR 1038(i) (Forest Fire Prevention Exemption), and categorical exclusions on federal lands approved under 36 CFR 220.6(e)(6)ii and (12}-{14).

SDG&E and PG&E recommend expanding this characterization to include biomass feedstock originating from fuel reduction projects undertaken by non-governmental organizations, such as Fire Safe Councils, homeowners' associations and other community-based entities. This suggestion appears to be unnecessary, given the broad scope of Pub. Res. Code § 4291, which applies to

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[43] *See*, e.g., the differing positions of CBD, GPI, and Placer APCD in their comments on the CALFIRE staff white paper.

any "private individual, organization, partnership, limited liability company, or corporation."[44] The IOUs' suggestion also has the potential to complicate the process of verifying the eligibility of fuels in this category, which is difficult enough, as can be seen from the discussion in section 2.2.4., below. This suggestion is not adopted.

The addition of projects conducted under various authorizations of activities for fuel hazard reduction, as set out in the CAL FIRE staff white paper, are a reasonable augmentation of the intention of this sub-category, and are adopted.

2.2.3.3. Infrastructure Clearance Projects

> **Infrastructure clearance projects.** ~~Bioenergy~~ Biomass feedstock ~~originating~~ derived from fuel reduction activities undertaken by or on behalf of a utility or local, state or federal agency for the purposes of protecting infrastructure, including but not limited to: power lines, poles, towers, substations, switch yards, material storage areas, construction camps, roads, railways, etc. This includes timber operations conducted pursuant to 14 CCR 1104.1(b)-(g).

There is little variation between the Staff Proposal and the CAL FIRE staff white paper phrasing of the characterization of this sub-category. CBD argues that the last sentence in both versions, which references CAL FIRE regulations about conversion of timberland to non-timberland uses (14 CCR 1104.1) is

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[44] The obligations of Pub. Res. Code § 4291 apply if a person or entity

> owns, leases, controls, operates, or maintains a building or structure in, upon, or adjoining a mountainous area, forest-covered lands, brush-covered lands, grass-covered lands, or land that is covered with flammable material.

Pub. Res. Code § 4291(a).

overbroad, potentially sweeping new construction projects into the scope of "fuel reduction activities."

SDG&E and PG&E recommend expanding the characterization of "Infrastructure Clearance Projects" to include all utility right-of-way fuel reduction activities done for the purpose of protecting infrastructure. This expansion would include water conveyance systems (canals, penstocks, flumes, tunnels, etc.), gas lines, and telecommunication lines.

The IOUs' suggestion is sensible and consistent with the purpose of this subcategory. By focusing on protecting infrastructure, but explicitly expanding the scope of the infrastructure covered, it provides greater clarity than the mere reference to 14 CCR 1104.1, while also removing the possibility that some activities authorized under 14 CCR 1104.1 could be inconsistent with the requirements of SB 1122.

We therefore adopt the following characterization:

> **Infrastructure Clearance Projects.** Biomass feedstock derived from 1) fuel reduction activities undertaken on behalf of a utility or local, state or federal agency for the purpose of protecting infrastructure including but not limited to: power lines, poles, towers, substations, switch yards, material storage areas, construction camps, roads, railways; and 2) all utility right-of-way fuel reduction activities undertaken for the purpose of protecting infrastructure, including water conveyance systems (canals, penstocks, flumes, tunnels etc.), gas lines, and telecommunication lines.

2.2.3.4. Other Sustainable Forest Management

With respect to the fourth sub-category of the Staff Proposal, "other sustainable forest management," there is a greater difference between the language of the Staff Proposal and the language of the CAL FIRE staff white paper. The Staff Proposal is set out first, with the CAL FIRE staff white paper language second.

> **Other Sustainable Forest Management.** Bioenergy feedstock certified and approved as being derived from 'sustainable forest management' by CAL FIRE or another appropriate State or federal agency. [Staff Proposal]
>
> **Other sustainable forest management.** Biomass feedstock derived from sustainable forest management activities that accomplish one or more of the following: 1) forest management applications that maintain biodiversity, productivity, and regeneration capacity of forests in support of ecological, economic and social needs, 2) contributes to forest restoration and ecosystem sustainability, 3) reduces fire threat through removal of surface and ladder fuels to reduce likelihood of active crown fire and/or surface fire intensity that would result in excessive levels of mortality and loss of fire cover or, 4) contributes to restoration of unique habitats within forested landscapes. [CAL FIRE staff white paper]

The Staff Proposal presents a methodology as the definition: bioenergy feedstock that has been certified by an appropriate agency as being derived from sustainable forest management practices. The CAL FIRE staff white paper provides a characterization of "sustainable forest management activities" as accomplishing four specific, though broad, objectives. The CAL FIRE staff white paper definition is supplemented by a "forest biomass sustainability byproduct eligibility form," attached as Appendix C to the CAL FIRE staff white paper.[45]

Parties express a range of views on these approaches. Most express some degree of dissatisfaction with the approach of the Staff Proposal, which simply points to activities of other agencies.[46] Placer APCD urges the Commission to adopt the definition put forward in the CAL FIRE staff white paper. CBD argues that the CAL FIRE staff white paper does not articulate any rationale for considering the activities it outlines to be "sustainable." GPI proposes some

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[45] This will hereafter be referred to as the "CAL FIRE staff eligibility checklist"

[46] CBD, Forest Trust, GPI, and Placer APCD critique the Staff Proposal on this point.

changes to the definition in the CAL FIRE staff white paper, while Forest Trust proposes its own definition.

Neither the Staff Proposal nor the CAL FIRE staff white paper definition meets the needs of SB 1122 implementation. The Staff Proposal defers completely to other agencies' processes. But the Staff Proposal provides no assurance that such other processes will be able to take into account all the elements needed for RPS eligibility, as well as SB 1122 eligibility—or even that such processes will take place at all.

The definition in the CAL FIRE staff white paper, however, is embedded in the same controversies about sustainable forest management that it attempts to resolve. For example, how should the term "regeneration capacity of forests" be understood by the Commission and by potential participants in the bioenergy FiT? Adopting this definition would put the Commission in the position of appearing to express a view on the same broad and contentious issues of sustainable forestry that we have concluded are unnecessary for this Commission to address in its implementation of SB 1122.

On the other hand, the "Forest Biomass Sustainability Byproduct Eligibility Form," attached as Appendix C-1 and C-2 to the CAL FIRE staff white paper, provides an operational characterization of "other sustainable forest management" through a detailed checklist to determine whether "sustainable forest management" has been used in areas that are the source of fuel for bioenergy projects. While the items on the checklist of course are connected to a <u>view</u> of sustainable forest management put forward by CAL FIRE staff, the checklist itself allows a range of <u>activities</u> to be used to demonstrate that a fuel

source meets the requirements of Section 399.20(f)(2)(A)(iii).[47] For purposes of implementing SB 1122, a publicly accessible list of forest management activities that will ground eligibility of generation using forest byproducts for the bioenergy FiT is appropriate. Debate on the important scientific and philosophical questions embodied in the concept of "sustainability" are appropriate for forums other than this decision.

We therefore modify the CAL FIRE staff white paper checklist in order to use it as the basis for the determination of eligibility of fuel under SB 1122, when eligibility is claimed on the basis that the fuel is the byproduct of other sustainable forest management practices not covered in the areas of fire threat reduction, fire safe clearance activities, and infrastructure clearance activities set forth above.[48]

2.2.3.5. Fuel Source Content

As with the other bioenergy technology categories, the general requirement that at least 80% of the fuel source, measured on an annual basis, must be of the type designated by the generator as the fuel source applies to the overall technology category of "by-products of sustainable forest management," as characterized in this decision.[49] If the generator chooses to use up to 20% fuel

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[47] For example, the first item on the checklist reads:

> Opening for shade intolerant species were created to promote regeneration and habitat diversity
>
> Please describe percent and distribution of areas in small openings less than 2.5 acres in size and planned regeneration methods.

[48] The checklist adopted in this decision is attached as Appendix B.

[49] To the extent that the basis for fuel source eligibility is "other sustainable forest management," the criteria of the checklist found in Appendix B must be satisfied.

not of the designated type, it must use fuel that complies with the requirements set out in this decision for eligibility under SB 1122.

The related issues of verification of fuel source eligibility for this and the other categories of bioenergy generation technology are discussed in section 2.2.4., below.

2.2.4. Fuel Source Monitoring and Verification

The fuel resource used by a generation facility is relevant to several elements of its participation in the bioenergy FiT. Most fundamentally, the RPS eligibility of the fuel source must be certified by the CEC.[50] The fuel source must also satisfy the terms of the definitions set forth in this decision. Further, the fuel source is one basis for allocation of the procurement targets to IOUs, as developed in section 2.4., below. Finally, the fuel source category will be part of the price adjustment mechanism for the bioenergy FiT, as explained in section 2.6.2.2., below. Accurate information about fuel sources is therefore important to the fair and efficient administration of the bioenergy FiT.

The Staff Proposal envisions two different circumstances in which a generator would be required to provide information to the IOU with which it contracts about its fuel source(s):

1. At the time the project submits its program participation request (PPR) form to participate in the bioenergy FiT;
2. Annually after the project has signed a contract, through a report from the generator to the IOU.

No party opposes the proposal that, at the time it submits a PPR to an IOU, a generator must provide information the type of fuel it intends to use, sufficient

[50] See Section II of the *Eligibility Guidebook* (7th.ed).

to demonstrate that the fuel resource is eligible under SB 1122 and to specify the fuel type. The generator must submit a similar attestation at the time of signing a contract under the bioenergy Fit. The IOUs are directed to provide a draft form of attestation for this purpose.

The parties' views of the Staff Proposal for annual monitoring of the bioenergy category of the fuel sources for a generation project, once it is online, are more varied. No party opposes the concept of monitoring fuel usage, but parties have differing views of the appropriate process.[51] AECA, GPI, and SCE support the Staff Proposal. Some parties consider the Staff Proposal duplicative of the existing RPS fuel usage verification process of the CEC.[52] Some parties assert that any monitoring of ongoing fuel usage should be done by a state agency or other third party, not the IOU.[53] Some parties suggest time periods other than annually.[54]

The Staff Proposal for annual monitoring of fuel usage is sensible and is adopted. The generator should provide an attestation that identifies the fuel used in the preceding year, including overall percentages of each fuel type, so that the IOU can easily ascertain whether the requirements of this decision for

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[51] BAC suggests that the monitoring should be similar to the FERC Form 556 for Qualified Renewable Facilities. FERC Form 556 refers to certifying a maximum of fossil fuel use at a generation facility. This is not an appropriate point of reference in the context of RPS compliance. To the extent that BAC uses this only as an example of certification by the generation facility, it is in accord with most parties.

[52] These include GPI, PG&E, and SDG&E.

[53] These include, albeit for differing reasons, Forest Trust, PG&E, and Placer APCD.

[54] Placer APCD suggests a five-year rolling compliance process. SDG&E asserts that, if a generator changes fuel, notification of the IOU should be immediate.

fuel category eligibility are being met.[55] The IOUs are directed to provide a draft form of attestation for this purpose.

Forest Trust and PG&E make suggestions for various forms of third-party monitoring and/or verification of fuel sources. These suggestions, while relevant, are premature. The Commission, the IOUs, and the market participants do not have enough experience with the types of small bioenergy projects mandated by SB 1122 to make definitive choices about monitoring by third parties. In order to lay the groundwork for a more informed decision on these issues, Energy Division staff may consult with parties and other agencies, as necessary, to discuss possibilities of third-party monitoring and verification. The Director of Energy Division should take more formal steps at an appropriate time to develop standards and a format for third-party verification of fuel sources for generators in all SB 1122 categories.

2.3. Allocation of MW Targets by Statewide Peak Demand

SB 1122 requires that each of the three large IOUs procure a share of the statute's 250 MW requirement based on the ratio of the IOU's peak demand to statewide peak demand. The Staff Proposal uses the same method implemented by the Commission in D.07-07-027[56] and followed in D.12-05-035[57] to establish these targets for the IOUs' obligations under SB 1122. Specifically, the ratio is

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[55] If any of the fuel used is in the "other sustainable forest management" group, the attestation must include a completed checklist, set out in Appendix B.

[56] D.07-07-027 at 9.

[57] D.12-05-035 at 77-79, Conclusion of Law 39.

calculated by comparing each utility's coincident peak demand to the total system statewide peak demand, yielding the following allocations.[58] These allocations are based solely on share of statewide peak demand, unmodified by other requirements of SB 1122. Table 4, in section2.4.2, below, provides the MW allocations based on satisfying all the statutory mandates, as explained in section 2.4.

Table 1

IOU	SB 1122 target based on share of statewide peak demand
PG&E	110.78 MW
SCE	114.53 MW
SDG&E	24.68 MW

2.4. Allocation of MW by Technology Category

SB 1122 also mandates a separate set of procurement targets, given as MW by technology category, set out in Section 399.20(f)(2)(A):

> (i) For biogas from wastewater treatment, municipal organic waste diversion, food processing, and codigestion, 110 megawatts.
> (ii) For dairy and other agricultural bioenergy, 90 megawatts.
> (iii) For bioenergy using byproducts of sustainable forest management, 50 megawatts. . . .

The statute does not provide any instructions for implementing the two types of targets together.

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[58] Some parties dispute this methodology. GPI suggests that a retail sales, rather than a capacity basis, is more appropriate for determining this allocation, since the RPS program is a program based on energy, not capacity. Whatever the merits of that view in the abstract, Section 399.20 specifies capacity targets. Reid argues that the total peak demand for the IOUs should be used to determine each IOUs' allocation. The statutory language, however, specifies "statewide" peak demand.

The Staff Proposal meshes the two procurement targets by using the concept of "resource potential" developed in the B&V Report. In the B&V Report, the consultants estimated the availability of fuel sources for each technology type in each IOUs' service territory. The parties generally support the estimates in the B&V Report. These estimates are used here with the understanding that they do not represent the results of precise surveys of the respective resources, but rather a reasonable estimate, based on a variety of sources, of the practical potential for fuel resources of each type in each IOU's service territory. With this understanding, the estimated resource potentials shown in Table 2 provide useful reference points for implementing the SB 1122 procurement targets.[59]

Table 2

IOU	Category 1 (MW)	Category 2 (MW)	Category 3 (MW)	Total Potential (MW)	SB 1122 Target (MW)
PG&E	101	340	478	919	111
SCE	115	118	16	249	114
SDG&E	26	3	3	32	25
Total	241	461	497	1200	250

It is clear from the table that the potential resources for generation facilities eligible under SB 1122 are not equally distributed among the service territories of the three IOUs. This makes the issue of how the MW targets for each technology category should be allocated somewhat more complicated than the simple statutory directives would suggest.

[59] This table is substantially the same as Table 1-1 in the Staff Proposal at 27.

2.4.1. Fire Threat Treatment Areas

One allocation is not reasonably open to dispute. Allocations of the 50 MW target for Category 3, byproducts of sustainable forest management, is required by Section 399.20(f)(2)(A)(iii) to:

> be determined based on the proportion of bioenergy that sustainable forest management providers derive from sustainable forest management in fire threat treatment areas, as designated by the Department of Forestry and Fire Protection.

A study published jointly by CAL FIRE and the CEC delineates "fire threat treatment areas" throughout the state.[60] Since the statute requires the Commission to use the areas delineated by CAL FIRE, this allocation formula is not subject to revision by the parties or the Commission. The consultants in the B&V Report used the information in the *Biomass Potentials* report to develop an allocation of Category 3 targets: 47 MW to PG&E; 2.5 MW to SCE; and 0.5 MW to SDG&E.[61] No party objects to the methodology used in the B&V Report. These targets are adopted.

2.4.2. Other Bioenergy Technology Categories

For the other technology types, GPI proposes that the targets by technology type should not be allocated to individual IOUs, but that the

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[60] The study, Biomass Potentials from California Forest and Shrublands Including Fuel Reduction Potentials to Lessen Wildfire Threat (February 2005; rev. October 2005) (*Biomass Potentials*) was published in 2005, but it remains the most current presentation of CAL FIRE's fire threat treatment areas. Fire threat treatment areas are shown in Fig. 8, at 25. This study may be found at http://frap.fire.ca.gov/publications/BIOMASS_POTENTIALS_FROM_CA_FOREST_AND_SHRUBLANDS_OCT_2005.pdf.

[61] The process of developing the allocations is discussed at A-5 *et seq*. in the B&V Report.

bioenergy market should be allowed to determine which technology types are built in which locations. Some other parties, including BAC, Placer APCD, and Sustainable Conservation, recommend targets for individual IOUs that are based on the proportions of the resource potential estimates. The Staff Proposal takes a different approach, discussed separately below.

While the GPI proposal is consistent with the overall market-based approach to RPS procurement, it is not consistent with SB 1122's particular prescriptive approach to the bioenergy segment of the RPS market. The statute's express requirements for allocations of the Category 3 target imply that the total MW targets for the other two categories will also be allocated among IOUs, rather than being left to the initiative of market participants.

The suggestion that the resource potential estimates in the B&V Report should govern the allocations of Category 1 (biogas from various sources) and Category 2 (dairy and other agricultural bioenergy) runs into mathematical difficulties. Applied directly, the resource potential estimates for Category 1 and Category 2 cannot be implemented consistent with the MW targets for each IOU, as shown in Table 3.[62]

Table 3

IOU	**Category 1:**	**Category 2**:	**Category 3:**	Total	MW target (statewide peak demand)
PG&E	46	66	48	161	**110.78**
SCE	52	23	2	77	**114.53**

[62] Although these are estimates of resource potentials, and thus not definitive, the magnitude of the variations from the target MW allocation for each IOU is large enough to be meaningful, even if the potentials used are estimates.

SDG&E	12	1	0	13	**24.68**
Mandated Total	110	90	50	250	

This method would allocate about 45% more MW to PG&E than its overall target, while allocating only about 68% of its overall target to SCE, and about 53% of its overall target to SDG&E.[63]

Parties propose variations on this model, modifying the MW allocations of the resource categories among the IOUs, based on relative abundance of resource potential, but not strictly following the B&V Report estimates. The approach of these parties, for example Sustainable Conservation, is to propose reallocations that would recognize the resource potential imbalance in various ways, but without identifying a basic method or structure for the reallocation.[64]

Recognizing the complexity of integrating the two allocation requirements, the Staff Proposal uses a "hybrid" methodology to allocate the total MW for Category 1 and Category 2 among the three IOUs. This methodology, which is implemented in the B&V Report, has five steps.[65]

1. Allocate Category 3 MW according to the statutory prescription.

2. Allocate Category 1 and Category 2 MW according to each IOU's share of statewide peak demand.

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[63] This method also disregards the special rules for allocation of Category 3 resources. The impact of that omission on the overall relationship of the proposed allocations to each IOU's MW target is, however, not significant in this context.

[64] The suggestions of BAC and Placer APCD involve reallocating MW in Category 3, which is not consistent with Section 399.20(f)(2)(A)(iii). These suggestions are therefore infeasible.

[65] See Staff Proposal at 29-31.

3. Reducing SDG&E's MW target for Category 2 from 11 MW (calculated pursuant to step 2) to zero, because the 11 MW target calculated greatly exceeds the estimated resource potential of 3 MW.

4. Reallocate the 11 MW from Category 2 to Category 1 for SDG&E.

5. Allocate the remaining Category 1 and Category 2 MW (a total of 176 MW) to PG&E and SCE by using an estimated blended cost range ($/MWh) from the B&V Report to optimize the expected estimated costs.

This methodology yields the following allocations by fuel resource category.[66]

Table 4

IOU	**Category 1:** Biogas from various sources	**Category 2:** Dairy & other agricultural bioenergy	**Category 3:** Byproducts of sustainable forest management	
PG&E	30.5	33.5	47	**111** (110.78)
SCE	55.5	56.5	2.5	**114.5** (114.53)
SDG&E	24	0	0.5	**24.5** (24.68)
SB 1122 mandated total	110	90	50	**250**

This methodology is supported by Forest Trust, ORA, SCE, and SDG&E. Significantly, no party objects to the Staff Proposal's use of the estimated blended cost range, in order to try to optimize estimated expected costs, as an element of its allocation methodology.[67]

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[66] For reference, numbers in parentheses show precise MW targets based on peak demand alone. *See* Table 1.

[67] SCE suggests that the Commission may need to revisit the allocations as the bioenergy FiT proceeds.

Implementing the procurement targets set out in SB 1122 requires meeting three separate statutory mandates:

1. Allocating the 250 total MW among the three IOUs according to their share of statewide peak demand;

2. Allocating the 50 MW of bioenergy using byproducts of sustainable forest management according to the fire threat treatment areas designated by CAL FIRE;

3. Procuring the targeted number of MW for each specified technology (110 MW from biogas from various sources; 90 MW from dairy and other agricultural bioenergy; and 50 MW from byproducts of sustainable forest management).

As the discussion in this section demonstrates, implementing all these requirements together is a complex undertaking. The Staff Proposal strikes an appropriate balance among the allocations required by SB 1122, the practical ability of IOUs and generators to implement the allocations by fuel resource type, and the delivery of the best value to ratepayers from the generation participating in the bioenergy FiT. The allocations for each IOU set forth in Table 4, above, are therefore adopted.

2.5. Participation in Bioenergy FiT

The fundamental structure of the FiT, with ReMAT as its centerpiece, has been set by the Commission in previous decisions.[68] This decision takes the previously approved elements as the basis for characterizing participation in the 250 MW procurement program set up by SB 1122, modifying the earlier elements where necessary to allow effective implementation of the SB 1122 mandates.

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[68] D.12-05-035, as modified by D.13-01-041, created the framework and rules. D.13-05-034 adopted a joint standard contract for the program.

2.5.1. Characteristics of the Generation Facility

A generation facility with a nameplate capacity of up to 3 MW AC is eligible to participate in any part of the RPS FiT, including the bioenergy focus implemented in this decision. (*See* D.12-05-035 at 65.)

A generation facility must meet the requirements of the CEC for certification as RPS-eligible, as set out in the *Eligibility Guidebook* that is in effect at the time the generation facility must demonstrate that it is RPS-eligible.

In order receive payment under the FiT, a generation facility must meet the requirements of the Federal Energy Regulatory Commission (FERC) for a qualifying facility (QF) for purposes of the federal Public Utility Regulatory Policies Act of 1978 (PURPA).[69]

Section 399.20(f)(2) makes the bioenergy FiT applicable only to bioenergy projects "that commence operation on or after June 1, 2013." There is no definition of "commence operation" in the statute. The Staff Proposal recommends looking to the CEC's *Eligibility Guidebook*. The *Eligibility Guidebook* does not define the term, but it does provide a definition for the closely related term, "commercial operations date."[70] The Staff Proposal recommends adopting

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[69] PURPA is codified in scattered sections of 16 U.S.C., including, § 796, § 824a-3 and §§ 2601, *et seq.*

The FERC provides two certification options for facilities to attain QF status, self-certification or FERC certification. Explanations and instructions are provided on the FERC's web site, at http://www.ferc.gov/industries/electric/gen-info/qual-fac/obtain.asp.

[70] The Glossary of Terms in the *Eligibility Guidebook* (7th ed.) at 117, provides:

> ***Commercial operations date (COD)*—**the date on which an electrical generation facility ceases to generate electricity for testing purposes and first generates electricity solely for the purpose of consumption by the facility or any customer or for sale to any procuring retail seller or POU; also referred to as commenced operation date in WREGIS.

Footnote continued on next page

the CEC's definition of commercial operations date to determine whether a bioenergy facility commences operation on or after June 1, 2013. This proposal is supported by Reid, SCE, and BAC (with some qualifications).

Because the CEC definitions are widely understood and applied within the renewable energy industry, it is reasonable to adopt the CEC's definition, with the clarification that the definition that controls is the definition in the *Eligibility Guidebook* that is in effect on the date that a generation facility submits its request for participation in the bioenergy FiT. This will prevent confusion among market participants and avoid administrative difficulties in trying to determine the controlling definition, should the CEC revise it in the future. The definition of "commercial operation date" in the CEC's *Eligibility Guidebook* is, with this qualification, adopted for determining whether a bioenergy facility commences operation on or after June 1, 2013.

2.5.2. Location of Generation Facility

2.5.2.1. Service Territory of IOU

Section 399.20 (b) defines a facility eligible for the RPS FiT as being "located within the service territory of, and developed to sell electricity to, an electrical corporation."[71] This requirement applies to eligibility for the bioenergy FiT as a matter of course.

The process for determining the commercial operations date for repowered facilities is set out in section III.D. of the *Eligibility Guidebook*.

[71] Section 399.20(b) provides in full:

> As used in this section, "electric generation facility" means an electric generation facility located within the service territory of, and developed to sell electricity to, an electrical corporation that meets all of the following criteria:

Footnote continued on next page

The ALJ Comment Ruling raised the issue of whether the fuel source(s) for the facility should also be located in the service territory of the IOU with which the generation facility contracts. AECA and CBD support the idea of restricting the location of fuel sources; most parties commenting on the issue do not.[72] Supporters of locational restrictions argue that locational restrictions are justified by environmental concerns related to the emissions of air pollutants that result from long-haul trucking of fuel resources. Other parties note that there is no statutory requirement that fuel sources be located in the same IOU territory; ORA suggests that allowing fuel sources from outside the IOU's service territory could help to distribute costs more equally among ratepayers.

Although the environmental concerns raised by parties are legitimate, they offer no clear way to address them. A limitation to the IOU's service territory is somewhat arbitrary. An IOU's service territory covers hundreds of miles, within which acquisition of various fuel sources would be allowed, while the territory of a neighboring IOU might be only a few miles away from some generation projects. AECA offers a fallback position of a radius of 50 miles from the project; CBD suggests a 25-mile radius; Reid suggests that the fuel source must be within

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(1) Has an effective capacity of not more than three megawatts.

(2) Is interconnected and operates in parallel with the electrical transmission and distribution grid.

(3) Is strategically located and interconnected to the electrical transmission and distribution grid in a manner that optimizes the deliverability of electricity generated at the facility to load centers.

(4) Is an eligible renewable energy resource.

[72] These include BAC, Forest Trust, ORA, PG&E, and Placer APCD.

the service territory of one of the IOUs. These suggestions show that there is no consensus on how to craft a limitation on fuel source by geography.

To the extent that trucking the large mass of material necessary for bioenergy facilities is an issue, it is likely that the costs of moving feedstock long distances will act as an economic deterrent to long-haul trucking. This is especially likely in the SB 1122 context because, as GPI points out, SB 1122 is directed to small generation facilities that are not likely to be able to support extra fuel expense. The suggestion to restrict the location of fuel sources is rejected.

2.5.2.2. "Strategically Located"

Section 399.20(b)(3) requires that an eligible generation facility must be "strategically located and interconnected. … in a manner that optimizes the deliverability of electricity generated at the facility to load centers." In D.12-05-035, as modified by D.13-01-041, the Commission determined that this language should be implemented by requiring that:

> a generator must be interconnected to the distribution system, as opposed to the transmission system, and sited near load, meaning in an area where interconnection of the proposed generation to the distribution system requires $300,000 or less of upgrades to the transmission system.

(D.12-05-035, Conclusion of Law 36.)

In practice, this monetary criterion is implemented by requiring that, at the time of FiT contract execution, the interconnection study for the project must estimate $300,000 or less in transmission system network upgrades. If the estimate is higher than $300,000, the generator is not eligible for the contract. However, if at any time after contract execution, a new estimate of transmission

network upgrade costs is higher than $300,000, the generator has the option to buy down the excess costs in order to maintain its eligibility.[73]

As PG&E and SCE point out, the criteria for "strategically located" were controversial and actively contested. The Commission's conclusion was arrived at on the basis of evaluating of substantial contributions from many parties, with vigorous advocacy of various positions. Recognizing this history, the Staff Proposal recommends requiring that bioenergy projects eligible under SB 1122 meet the same standard in order to be considered "strategically located."

Several parties urge the Commission to take a more expansive view of this requirement in the context of SB 1122.[74] They point out that, for example, bioenergy projects located on large dairy farms are not going to be able to meet this requirement, because almost by definition such locations are not close enough to load centers to interconnect at the distribution level without significant transmission upgrade costs. Similarly, many projects using byproducts of sustainable forest management may be in locations that are so remote that they will not meet this criterion.

The physical reality to which these comments refer makes it necessary to revise the Commission's implementation of the "strategically located" criterion in order to implement SB 1122 effectively. It will not be possible to "optimize the deliverability of electricity generated at the facility to load centers" if no electricity is generated, because no facility can meet the current "strategically located" eligibility criterion. Any revision of this criterion will apply only to

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[73] Staff Proposal at 9.

[74] These include AECA, BAC, Dairy Cares, and Sustainable Conservation.

projects participating in the SB 1122 bioenergy FiT tariff; it will not apply to other projects using the ReMAT tariff.

BAC, supported by AECA and Dairy Cares, proposes to modify the criteria for "strategically located" to include "located in a geographic area necessary to meet state legislative requirements."[75] This suggestion would read the "strategically located" requirement out of the statute altogether, since another way to express the BAC suggestion is, "eligible under SB 1122." Such wholesale rewriting is not appropriate.

BAC makes an alternate suggestion that does have merit. BAC, supported by AECA, Dairy Cares, and TURN, proposes that a generator should have the option of shouldering the transmission network upgrade costs in excess of $300,000 at any time in the process of participating under the tariff. This maintains the benchmark that the Commission has previously established and does not introduce any socialized interconnection costs, but allows flexibility needed to implement SB 1122.

Unlike the current ReMAT process, under the proposed modified SB 1122 process an initial estimate of transmission network upgrade costs in excess of $300,000 would not disqualify a generation project. Instead, the generator could commit to paying the transmission network upgrade costs in excess of $300,000 at any point, including at contract execution, in order to establish and maintain eligibility. This modification of the criteria for determining that a generation project is "strategically located" is adopted. The IOUs should include appropriate provisions in the joint draft tariff for the bioenergy FiT to implement

[75] BAC Comments at 15.

this option in a manner consistent with the fair and efficient administration of the tariff.

The criterion that a generation project must be interconnected at the distribution level remains in place for both general ReMAT and SB 1122-eligible projects.

2.5.3. Participation in SB 1122 and ReMAT

The Staff Proposal, concerned about creating opportunities for the exercise of market power by projects eligible for both SB 1122 and the general ReMAT, proposes to exclude a generation project that is eligible to participate in the bioenergy FiT from participating in the general ReMAT. This proposal is supported by ORA and SCE, on the grounds that it is important to discourage "program shopping" and to avoid overlapping procurement programs for small generators. TURN, supported by CBD, agrees with the general principle of the Staff Proposal, but seeks the clarification that projects eligible under SB 1122 may continue to participate in the general ReMAT until the new bioenergy tariff is available.

BAC, PG&E, and SDG&E propose to reduce the risk of gaming with a rule that a generation project would be able to participate in either program, but not in both at the same time for the same project.[76]

There is no statutory guidance on this issue, as BAC and Reid note. Parties generally agree that the risks of gaming and inefficient allocation of generation resources between the two programs is real. The Staff Proposal would address these risks by building a wall between participation in the bioenergy FiT and in

[76] Placer APCD supports this position as a second choice to its preferred outcome, that a project could bid into both general ReMAT and the bioenergy FiT simultaneously.

the general ReMAT program. This would solve the problem, but it also introduces an element of inflexibility that is not necessary in order to administer both FiT programs fairly and effectively.

The interests of ratepayers and other market participants can be protected by requiring that a project may only be bid into one program, and may only be maintained in the queue for one program. This will allow generation developers the freedom to choose the better program for their projects. It will also prevent the same project from being counted twice for market participation requirements, as PG&E notes, and from unproductively taking up a place in an IOU's queue of bidders.[77]

2.5.4. Limit on MW Offered

The current ReMAT limits the number of MW that can be offered for subscription in any program period to 5 MW for each of PG&E and SCE, and 3 MW for SDG&E. The Staff Proposal carries this forward.

Clean Coalition suggests that the maximum number of MW offered for the bioenergy FiT be changed to a multiple of 3, in order to maximize the opportunity for economies of scale in bioenergy facilities. PG&E and SCE would thus offer 6 MW, and SDG&E would remain at 3 MW. No parties oppose this suggestion. It is a reasonable adjustment that could help to improve the prospects for projects eligible under SB 1122, and is adopted.

[77] If a generation developer were to decide that its project really belonged in the RPS FiT program into which it had not bid, it would be free to withdraw its program participation request and start over in the other program.

2.6. Price

The Staff Proposal for the tariff for projects eligible under SB 1122 follows the design of the ReMAT tariff already in place. In particular, the Staff Proposal is intended to allow the bioenergy FiT to comply both with the Legislature's directives for the program, and with federal pricing requirements under PURPA. Parties have differing views about how to implement the requirements of fidelity to legislative requirements and consistency with PURPA requirements. Before turning to a specific discussion of the parties' positions, a review of the basic principles for compliance with PURPA, as explained in the RPS FiT decisions, is in order.[78]

2.6.1. Principles of Avoided Cost

The principles of avoided cost pricing as applied to the RPS FiT (and thus to the bioenergy FiT) are summarized in D.12-05-035, as modified by D.13-01-041, at 12-13. The basis for the Commission's discussion is an order of the FERC, *California Public Utilities Commission* (2010) 133 FERC ¶ 61,059 (*FERC Clarification Order*). The *FERC Clarification Order* clarified that a state has a wide degree of latitude in setting avoided cost. The discussion in our prior decision is as relevant to the bioenergy FiT as it was to the broader FiT discussed there, and is worth reproducing here.

> FERC has affirmed a state's ability to "determine that capacity is being avoided, and … rely on the cost of such avoided capacity to determine the avoided cost rate." FERC stated:
>
> > Further, in determining the avoided cost rate, just as a state may take into account the cost of the next marginal unit of generation, so as well the state may take into

[78] D.12-05-035, as modified by D.13-01-041.

> account obligations imposed by the state that, for example, utilities purchase energy from particular sources of energy or for a long duration.

Based on the *FERC Clarification Order*, we determined in D.11-04-033 that we have a wide degree of latitude in setting the avoided cost. We apply the same logic for the § 399.20 FiT Program. Specifically, based on the FERC's clarification, the Commission may adopt avoided costs differentiated for particular sources of energy that a utility must purchase. In addition, the Commission may adopt a multi-tiered avoided cost rate structure.[79]

Parties express differing views on the most appropriate way to implement these principles in the bioenergy FiT. We begin by reviewing the Staff Proposal.

The Staff Proposal adopts, adapts, and updates the methodology used in D.12-05-035 to determine a structure for the market-based tariff for the bioenergy FiT. There are three principal elements to the Staff Proposal methodology:

1. Use a single statewide "starting price;"
2. Determine the starting price by taking the weighted average of the bid prices (adjusted for time of delivery (TOD)) of all bioenergy projects bid into the first four auctions under the renewable auction mechanism (RAM) established in D.10-12-048; and
3. Allow the starting price to adjust for each technology category, on a statewide basis for each category.

2.6.2. Statewide Starting Price

Most parties support the use of a single statewide starting price;[80] i.e., the initial tariff price prior to any periodic adjustments for market interest.[81] The

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[79] D.12-05-035, as modified by D.12-01-041, at 13. Internal references and footnotes omitted.

[80] These include BAC, GPI, ORA, PG&E, SCE, and SDG&E. Some parties, including Forest Trust, Reid, and Sustainable Conservation, argue that starting prices should be set differently for each technology category.

single starting price is consistent with the Legislature's designation of "bioenergy" as the area of concern addressed by SB 1122. It also follows the path set in D.12-05-035, as modified by 13-01-041, for the initial starting price for ReMAT generally.

2.6.2.1. Based on Bioenergy Bids into RAM

In order to develop an initital starting price for the bioenergy FiT, the Staff Proposal looks to the same source as the RPS FiT—recent RAM auctions. Unlike the situation for the general RPS FiT, however, there are no currently successful bioenergy bidders in RAM. Bioenergy bids have been submitted in RAM auctions, but not selected.

It is important to remember that the Legislature enacted SB 1122 in part because bioenergy technologies were not being procured through the Commission's RPS procurement processes directed toward smaller generation projects: the RPS FiT, for projects up to 3 MW; and RAM, for projects up to 20 MW. The Staff Proposal adopts "the weighted average of all conforming bids into the first three RAM auctions from bioenergy projects" as the best estimate for the starting price for the bioenergy FiT. That starting price, as calculated in the Staff Proposal, is $124.66/MWh (pre-TOD).

Parties have mixed responses to the Staff Proposal. AECA, BAC, Dairy Cares, Placer APCD, and TURN generally support it as the initial starting price, though all have reservations and make various suggestions for the price adjustment mechanism, discussed in section 2.6.2.2. below. GPI and Sustainable Conservation argue that the starting price is too low to support certain bioenergy

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[81] See the succinct explanation of the operation of the ReMAT tariff, updated from the Staff Proposal, in Appendix C to this decision.

technologies. The IOUs each argue that the starting price is too high. Each has a different proposal for changing it. PG&E and SDG&E argue that executed RAM contracts, rather than bids, should be the source of price data. SCE proposes either using bid data from RAM 4 or the pre-TOD weighted average from the first three RAM auctions. ORA also claims that the use of post-TOD bid prices unnecessarily elevates the starting price; instead, pre-TOD prices of RAM bids should be used.

The Staff Proposal appropriately takes into account both the intent of the Legislature and the realities of the RPS market for small bioenergy projects. In doing so, it provides a sound approach to setting the initial starting price consistent with avoided cost principles. Although PG&E and SDG&E advocate the use of executed contracts rather than bids, they do not identify any bioenergy contracts that have in fact been executed pursuant to RAM. This leaves the bioenergy bids in RAM as the best available data.

Some parties argue that using post-TOD bid prices in RAM will make the pre-TOD starting price for the bioenergy FiT unjustifiably high; ORA suggests this is a form of double-counting of TOD value. This argument misses the mark. Since RAM bids are not negotiable as to price,[82] the post-TOD RAM bid price represents the price that the utility would actually have paid, if it had accepted the RAM bid. In the absence of executed contracts, the post-TOD bid price presents the most realistic representation of the cost to the IOUs of small bioenergy projects of all types.

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[82] D.10-12-048, OP 1.

However, since the Staff Proposal was issued, a fourth RAM auction has been completed. It is therefore reasonable to include the post-TOD prices in the fourth RAM auction with the post-TOD prices in the first three auctions as part of the weighted average price that sets the initial starting price for the bioenergy FiT. Using the weighted average post-TOD bioenergy bid prices in the first four RAM auctions yields an initial statewide starting price for the bioenergy FiT of $127.72, pre-TOD.[83] This initial starting price is adopted.

2.6.2.2. Adjustments to Price

A distinguishing characteristic of the ReMAT tariff is that it adjusts, based on market interest and behavior. The Staff Proposal adapts the basic ReMAT adjustment plan, explained in Appendix C to this decision, for purposes of the bioenergy FiT. Parties raise a variety of issues with respect to several aspects of the adjustment proposal.

2.6.2.2.1. Technology Category

The Staff Proposal provides that the initial statewide starting price would adjust for each bioenergy technology category, on a statewide basis. This would allow the bioenergy FiT price to adjust at different rates for the different bioenergy technology categories, while preserving a statewide market for each category.

The statewide market for each category is important because, as parties agree, the fuel resources specified in SB 1122 are not evenly distributed

[83] Because RAM bid data are confidential, Energy Division staff made this calculation using confidential data.

throughout the service territories of the three IOUs.[84] SCE, however, objects that having separate technology categories that will affect the price adjustment segments the market too much to be consistent with avoided cost principles.

In making this argument, SCE improperly discounts the fact that the Legislature specifically identified procurement targets in MW by technology category. The Legislature's policy has set these category goals. The Commission seeks to implement these goals consistent with avoided cost and ratepayer protection principles.

Parties' comments inform us that there are likely to be material differences in the markets among the different technology types. Adjusting the price on a statewide basis by technology category maximizes the likelihood that there will be enough interested projects in each category to support a robust market for the bioenergy FiT statewide.

We therefore adopt the general principle that the statewide starting price will adjust separately for each bioenergy technology type.

2.6.2.2.2. Dairy Projects

A number of parties argue for a separate treatment of the pricing of dairy projects.[85] They assert that bioenergy from dairy waste is known to be more costly than bioenergy from other agricultural fuel resources; thus, without some mechanism to separate dairy from "other agricultural" bids, effectively no dairy projects will be able to use the bioenergy FiT, because the category will be fully

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[84] The B&V Report makes detailed estimates of these resource potentials. It is not necessary for parties to agree about every numerical estimate in the B&V Report in order for them to agree—as they do—on the overall picture of very uneven distribution of resources among IOU service territories.

[85] These include AECA, BAC, Dairy Cares, Farm Bureau, GPI, and Sustainable Conservation.

subscribed by "other agricultural" projects. Some parties suggest that the Commission should split the MW allocation between dairy and "other agricultural." BAC also suggests what it terms a "price screen," which would allow the price for dairy projects to adjust separately from the price for "other agricultural" projects.

PG&E, ORA, and SCE assert that there is no statutory basis for carving out two sub-categories of "dairy and other agricultural bioenergy." Doing so could also, they argue, make the bioenergy FiT uncompetitive for those technologies, by constraining the universe of bidders.

This objection has some force with respect to the proposal to split the MW allocation between the two technology types. SB 1122 clearly allocates the 90 MW target to "dairy and other agricultural bioenergy." The proponents of the MW split have cited no basis in the statutory language or legislative history for the split, and there appears to be none. That suggestion is rejected.

The "price screen" idea, also supported by TURN, is on firmer ground. The drafting history of SB 1122 shows that, for much of the bill's life prior to enactment, "dairy digester gas" was a separate category.[86] This suggests that there is not an immutable connection between "dairy" and "other agricultural" bioenergy. By allowing the price of each type of project to adjust separately, the Commission can maximize the opportunities for both types of projects to contribute to the attainment of the Legislature's goals.

The separate price adjustment for each type that we adopt here does not, however, change anything about the overall allocation of the "dairy and other

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[86] The successive drafts of the bill may be found at http://www.leginfo.ca.gov/cgi-bin/postquery?bill_number=sb_1122&sess=PREV&house=B&author=rubio.

bioenergy" MW targets. The separate price adjustment is not intended as, and should not be construed as, any guarantee that any "dairy" projects will obtain a contract under the bioenergy FiT (or that any "other agricultural bioenergy" project will do so). If all or most of the MW allocation is subscribed by "other agricultural" projects, even with the separate price adjustments in place, that outcome would be consistent with the statutory language and the structure of the ReMAT-based pricing mechanism for the bioenergy FiT.

2.6.2.2.3. Minimum Number of Bids to Adjust Price

The Staff Proposal maintains at five the minimum number of conforming bids necessary to trigger a price adjustment for the next two-month program period. PG&E argues that this number is too small if prices are going to be set, and adjusted, on a statewide basis. BAC, Forest Trust, and Placer APCD urge the Commission to reduce the number, in order to get the market started with the potential projects that actually exist, or might exist in the near future. TURN proposes a temporary reduction in the number of bids required, with the number returning to five once at least one project in the technology type accepts the offer price.

TURN's suggestion is fair and sensible. It allows the price adjustment mechanism to reflect the existing market at the start of the bioenergy FiT, while maintaining the ReMAT rules over the longer term. A minimum of three eligible bids per technology type will be sufficient to trigger a price adjustment, until one project in the technology category accepts the offer price. At that point, the minimum number of bidders required to prompt a price adjustment in that technology category will revert to five.

In light of our decision to allow separate price adjustments for dairy projects and "other agricultural" projects (section 2.6.2.2.2., above), it is

reasonable to apply the minimum number of bids to each type of project in this category. Thus, the price for dairy projects will not adjust unless there are conforming bids from three eligible dairy projects statewide; the price for "other agricultural" projects will not adjust unless there are conforming bids from three eligible "other agricultural" projects statewide. Once a project accepts the offer price in each category, the minimum number of bids needed to prompt a price adjustment will revert to five for each category.

A subsidiary question has been raised by PG&E, and contested by some parties, about whether there should be a restriction on counting "affiliates" as part of the minimum number of bidders. This issue can be explored in the current FiT contract made available by PG&E.[87] BAC and AECA assert that precluding "affiliates" reintroduces the "seller concentration" limitation that was rejected in D.13-05-034. PG&E, supported by CBD, claims that the affiliate requirement helps to prevent market manipulation. No party commenting on the issue has, however, provided any information about the structure of participants in the small bioenergy market that could support its assertions. The provisions of the existing tariff definition provided by PG&E will therefore be

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[87] In its Definitions, Appendix A to the contract, PG&E includes the following:

> "Affiliate" means, with respect to a Party, any entity that, directly or indirectly, through one or more intermediaries, controls, or is controlled by, or is under common control with that Party.

Available at http://www.pge.com/en/b2b/energysupply/wholesaleelectricsuppliersolicitation/ReMAT/index.page.

carried forward, as the general rule for the bioenergy FiT; no clarification is needed in this decision.

2.6.2.2.4. Timing and Amount of Price Adjustment

The ReMAT price adjusts bi-monthly, in increments of $4/MWh per program period. The adjustment increment is capped at $12/MWh. BAC and AECA urge that the adjustment be accelerated to monthly, at least until one project in the technology category accepts a contract.

PG&E argues that the ReMAT price adjustment mechanism should not be altered for SB 1122 purposes, both because the mechanism was developed with extensive input from the parties and because it is a primary method for ensuring that ratepayers are protected from unnecessary expense in the program. Although it is true that reducing the adjustment interval to monthly would increase the tariff price more quickly, neither BAC nor AECA explains how that would be in the interest of ratepayers. In the absence of such justification, there is no reason to change the ReMAT adjustment interval.

PG&E also requests clarification that no change in the ReMAT increment cap of $12/MWh/period is intended in this decision. This falls within the general area of maintaining ReMAT provisions unless it is necessary to change them for a specific reason important for implementation of SB 1122. No change in this provision is intended or made by this decision.

2.6.3. Price Cap

Although the general ReMAT program does not include any cap on the price per MWh for a contract, several parties urge the Commission to impose a

price cap for the bioenergy FiT.[88] PG&E proposes a cap of 200% of the average of all executed RAM contracts. SCE proposes a cap of $197/MWh. TURN supports the PG&E proposal.

The proposal of a firm price cap is opposed by AECA, BAC, GPI, and Sustainable Conservation. GPI points out that SB 1122 does not include any direction to the Commission to create a price control mechanism. AECA and BAC prefer that the Commission actively monitor the price adjustment in the bioenergy FiT, and undertake a program review if prices become elevated. BAC suggests that SCE's proposed cap of $197/MWh be the trigger for Commission review.

We share the parties' concerns about the costs to ratepayers of implementing SB 1122. GPI notes that "in order to successfully implement SB 1122, the utilities will almost surely have to procure some very expensive power…"[89] Nevertheless, the Legislature mandated procurement pursuant to SB 1122 as part of the RPS program.

The Legislature did not require a particular cost containment mechanism for SB 1122 projects, though it has required that the Commission set a general RPS procurement expenditure limitation for the IOUs, pursuant to Section 399.15(c). The Commission has started the process of setting the overall RPS procurement expenditure limitation. It is reasonable to conclude that if the costs of SB 1122-eligible projects became so high as to interfere with the IOUs'

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[88] These include PG&E, SCE, and SDG&E, with the qualified support of ORA and Placer APCD.

[89] Comments of Green Power Institute on Staff Proposal, at 1.

attainment of their overall RPS procurement goals, that would be brought to the Commission's attention through the procurement expenditure limitation procedure, thus making it unnecessary and potentially confusing to set a separate price cap for SB 1122 projects only.

It is difficult to predict how expensive the contracts for projects eligible under SB 1122 might be.[90] That is one of the reasons that the ReMAT approach is valuable: it does not require the Commission to pretend to have a crystal ball within which it can view the future of the market for bioenergy from small generation facilities in California. Instead, the ReMAT methodology we apply to the bioenergy FiT allows market participation to be fully expressed in the price ultimately arrived at for a specific project.

Imposing a firm price cap on the bioenergy FiT is premature, and may ultimately be unnecessary. However, we agree that there should be a price point at which a review of the program pricing is appropriate. We therefore authorize the Director of Energy Division to initiate a review process, with notice to the service list of the proceeding having oversight over SB 1122, at any time after the price for any technology category reaches $197/MWh and remains at that price, or increases, over two program periods. We also authorize, but do not require, the Director of Energy Division to temporarily suspend the awarding of contracts

[90] Parties generally accept the ranges of projected costs presented in the B&V Report in evaluating pricing for the bioenergy FiT; indeed, SCE's price cap proposal is based on the B&V Report's" blended cost range." It is not necessary to decide that any particular cost outcomes are likely in order to formulate an approach to the possibility that costs for procurement pursuant to SB 1122 will be large enough to suggest that a review is in order.

in any technology category that is under review because the price has hit the price trigger set forth in this decision.

The IOUs retain the ability, established in D.12-05-035, to file a motion at any time that they believe that market manipulation or other market malfunctions are occurring in the bioenergy FiT. PG&E suggests that the IOUs be given the power to halt the bioenergy FiT by filing a Tier 1 advice letter if they suspect market manipulation or other market malfunctions are occurring. This proposal would remove oversight of the functioning of the bioenergy FiT from the Commission and give it to the IOUs. PG&E offers no reason, other than the potential for higher costs, to make such a significant change to the program from the basic ReMAT process. PG&E's suggestion is rejected.

2.6.4. Cost Sharing

PG&E, SDG&E, and Placer APCD all suggest some kind of cost sharing or cost allocation mechanisms. PG&E is concerned about what it perceives to be its disproportionate responsibility for meeting SB 1122 procurement targets. SDG&E argues that IOUs' procurement obligations under SB 1122 are analogous to their obligations to procure capacity for reliability needs, and thus the costs should be shared among all customers in the IOUs' service territory, including those not taking service from the IOU. Placer APCD suggests distributing costs annually among IOUs, based on peak load.

These proposals all miss the mark. They overstate the significance of the SB 1122 procurement obligations in the context of the IOUs' overall RPS procurement obligations, much less in the context of IOUs' total procurement requirements to serve their customers. Each IOU will receive cost recovery for its bioenergy FiT procurement expenses, just as it does now for ReMAT procurement expenses. If these expenses threaten an IOU's ability to meet its

overall RPS procurement obligations within any cost containment mechanisms that may be established, the IOU could address that threat through the cost containment process. There is no good reason to create a complex cost allocation sub-process within the general RPS procurement and expenditure limitation processes.

2.6.5. Administration of Statewide Price Pool

The Staff Proposal explores the important distinction between all IOUs' cooperation in providing the basis for a statewide price for separate bioenergy categories, and an individual IOU's maintenance of its own queue of program participation requests. Parties do not have any serious objections to the administrative structure outlined in the Staff Proposal. This structure, revised to be consistent with the requirements of this decision, is adopted. The structure is:

1. Individual projects submit PPRs directly to a single IOU (the utility in whose service territory the project intends to locate).

2. Each IOU will maintain its own queue for participation for each of the SB 1122 categories.

3. Execution of a bioenergy FiT contract by a bioenergy project will result in the capacity of that project being attributed to the SB 1122 capacity target for the IOU with which the project signs its contract.

4. The IOUs will jointly administer a statewide "price pool" for each of the SB 1122 bioenergy pricing categories,[91] in order to establish a single, statewide payment rate for each of the pricing categories.

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[91] They are: biogas from various sources; dairy bioenergy; other agricultural bioenergy; and bioenergy from byproducts of sustainable forest management.

5. The conditions for a price adjustment set out in this decision will be evaluated by considering the *cumulative participation* per pricing category statewide.

2.7. Contract and Administration Issues

The ReMAT tariff and standard contract remain the basis of the bioenergy FiT. As discussed throughout this decision, some adjustments and variations are required to accommodate the particular elements of the bioenergy generation sources identified by SB 1122. In this section, more detailed elements of possible revisions to contract terms and focused administrative issues are addressed.

2.7.1. Maintaining Fuel Source

2.7.1.1. Reporting

As discussed in section 2.2.4., above, a generator will be required to provide the IOU with an annual attestation of fuel use for the preceding year, sufficient for the IOU to be able to determine whether the facility is in compliance with its fuel source requirements. As with all self-reporting mechanisms, the attestation is only effective if it is completed conscientiously and submitted in a timely manner. Parties present a range of ideas for sanctions, some focused on the reporting itself, some on the consequences of a determination that a generator is not complying with its fuel source obligations.

SCE proposes that failure to report be considered an event of default, with a period for cure. This approach, while emphasizing the seriousness of the reporting obligation, moves immediately to a major confrontation between the IOU and the generator, even if it allows a 180-day period for cure.

It is reasonable to include a small but meaningful penalty for failure to timely provide the annual attestation, in order to provide an incentive for generators to submit the attestation on time. A penalty of $1,000 for every two

weeks the attestation is late sends the appropriate signal of seriousness for the submission, without being an excessively punitive response to simple administrative errors.

However, a failure to report should not be able to be continued indefinitely, simply for a nominal fee on the generator. An annual report that is not submitted within four months of the date it is due may be treated by the IOU as evidence that the generator is not in compliance with its fuel source maintenance obligations.[92] The IOUs should include an appropriate form for the sanction for failure to timely submit the annual report in their revisions to the basic ReMAT form.

2.7.1.2. Failure to Maintain Fuel Source

Most parties commenting on the issue agree that meeting fuel source requirements is an important element of the generator's responsibility under the bioenergy FiT.[93] SCE's proposal that the utility has the right to audit the generator's fuel use is not unreasonable, but PG&E, SDG&E, and Reid object to the IOU having responsibility for verifying fuel source use. It is reasonable for

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[92] SDG&E argues that an immediate notification to the IOU should be made if the generator "fuel switches." In view of the rules for fuel source set out in this decision, it is not clear to what actions by the generator SDG&E's concern would apply.

To the extent that SDG&E's suggestion relies on the procedures of the CEC with respect to verification of fuel source for purposes of RPS eligibility, that reliance is misplaced. The CEC's fuel source rules are directed to the maintenance of RPS eligibility, in accordance with the RPS eligibility rules in the CEC's *Eligibility Guidebook*. They do not address the more specific fuel resource categories in SB 1122, as elucidated in this decision. The application and verification forms used by the CEC may be found at http://www.energy.ca.gov/renewables/documents/.

[93] These include Forest Trust, PG&E, Placer APCD, Reid, SCE, and SDG&E.

the contracting IOU to be able to review, on reasonable request, the documentation on which the generator's annual attestation is based.[94] We defer the issue of any more extensive powers an IOU could have to the more general examination of third-party verification, which we authorize the Director of Energy Division to undertake. (See section 2.9., below.)

SCE's proposal of declaring an event of default and allowing a period to cure is more appropriate for actual failures to maintain the designated fuel source, within the rules set forth in this decision. If the annual attestation is more than four months late, the IOU may consider the generator not in compliance with its fuel use obligations under the contract and may declare an event of default.

If a failure to meet the fuel use requirements is shown in the generator's timely annual attestation, a more nuanced approach may be needed. The failure to meet the fuel use requirements occurred in the past, in the year being reported on. The IOU may declare an event of default on receiving an attestation that shows past failure to comply with the fuel use requirements. The generator may cure the default by providing monthly reports that show compliance with fuel use rules for the six consecutive months following the IOU's declaration of an event of default.

2.7.2. Other Proposed Changes to ReMAT Contract

Parties make a number of suggestions for revisiting and revising elements of the basic ReMAT contract. We consider them briefly here, and evaluate them

[94] The IOUs should include an appropriate provision in their proposed draft tariff.

according to the standard of whether they are necessary to allow the mandates of SB 1122 to be met.

2.7.2.1. Inflation Adjustment Adder

AECA, BAC, Phoenix Energy, and Placer APCD propose that an inflation adder of some proportion of the increase in the consumer price index be built into the bioenergy FiT. PG&E and SCE oppose this suggestion, arguing that it is inconsistent with the general approach in PPAs for the RPS program.

The IOUs are correct that an inflation adder is not appropriate. One of the principal ideas of a feed-in tariff is to create price certainty, for both buyer and seller. The proponents of this change advance no strong reason for making the bioenergy FiT less certain, as well as inconsistent with the basic ReMAT and broader RPS procurement policies. This suggestion is not adopted.

2.7.2.2. Interconnection Delays

BAC and Placer APCD propose that interconnection delays attributable to the IOU should not be cause for contract termination. As proposed, this suggestion sweeps more broadly than the existing ReMAT term, which allows a six-month extension of the online date if the generator has taken all reasonable actions but has failed to secure the necessary commitment from the CAISO or the transmission or distribution owner. There is no reason to introduce a variation on this basic element of the ReMAT contract for bioenergy projects. This suggestion is rejected.

2.7.2.3. Energy Production Issues

BAC proposes that the generator should be allowed more than one change in the quantity of energy contracted for. SCE and SDG&E oppose this suggestion as providing too much room for possible gaming of bioenergy FiT contracts. This proposal is rejected, both because it is an unnecessary complication to what

is supposed to be a simple procurement mechanism and because this particular complication could provide opportunities for gaming.

Phoenix Energy proposes to change the status of on-site energy use to exclude it from provisions on guaranteed energy delivery. SCE opposes this change to the general ReMAT provision. This proposal is rejected. The risk of variable onsite load is properly borne by the generator, not by ratepayers.

BAC, Dairy Cares, and Placer APCD propose a change to the ReMAT guaranteed energy production requirement for baseload facilities.[96] BAC argues that the nature of the technologies eligible under SB 1122 may lead to greater variation in energy production. Instead of requiring 180% of the contracted energy to be delivered over two consecutive years for all years of the contract, BAC proposes that, in the first two years of the contract, the generator be allowed to deliver 140% of the contracted amount.[97] This suggested change is inconsistent with the ReMAT treatment of the same types of generation and would have the effect of shifting the risk of variable energy deliveries from the generator to ratepayers. It is rejected.

2.7.2.4. Damages and Penalties

ORA suggests that a provision for liquidated damages should be included. A liquidated damages term is already part of the ReMAT contract, so no further action is required.

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[96] There is no dispute among the parties that generation facilities eligible under SB 1122 would belong in the "baseload" category of the current ReMAT contract.

[97] This is the figure for the non-peaking, as available category (principally wind generation) in the current ReMAT contract.

BAC and Phoenix Energy suggest that the current forecasting penalties are too high, in that they are disproportionate to any actual damage suffered by the IOU. Whether or not this assertion has any merit, the situation is not different for any generation participating in the RPS FiT. There is no reason to make a special rule for generators eligible under SB 1122.

2.7.2.5. Miscellaneous Contract Issues

Reid makes several suggestions for changes to standard terms in use for ReMAT, including adjustments to times for providing notices; the content of the force majeure provision; and the content of the provision on recovery of attorneys' fees. None of these changes is connected to anything that is necessary in order to facilitate the integration of the SB 1122 mandate into the RPS FiT. To the extent the proposed changes would affect all ReMAT contracts, they should be proposed in a context in which they could be given general consideration. These proposals are rejected.

Dairy Cares, supported by AECA, requests a special system for TOD factors as applied to projects eligible under SB 1122. This proposal would change the way updates to TOD factors are treated throughout the RPS program, for the possible (though not assured) benefit of making some dairy digester projects more feasible. Such a systemic change for such a relatively small segment of the RPS procurement universe is not justified. This proposal is rejected.

2.7.3. End Date for Program

The general FiT will terminate "24 months after the first product type goes to zero MW or goes to a *de minimis* amount approaching zero." (D.13-05-034, Conclusion of Law 5.) The IOUs each propose that the bioenergy FiT also have a "sunset" date, to provide certainty to IOUs and developers, as well as to put some limit on the movement of prices over a large number of years. SCE makes

the concrete proposal that the sunset date be 42 months from the program starting date. AECA, BAC, and Placer APCD oppose the proposals for sunset dates.

Because the ReMAT has a sunset date, it is reasonable to include a termination date for the bioenergy portion of the RPS FiT program. The date set in D.13-05-034 will not be appropriate for the bioenergy FiT, however, both because the bioenergy FiT will be starting more than a year later and because the dynamics of the two markets may well be different.

SCE's proposal is based on its estimate of how long it would take projects to complete the interconnection process. This proposal does not take account of the information provided in comments, and generally assumed by the parties, that projects eligible under SB 1122 are likely to enter the market at different times. Some types of projects may be ready to go fairly quickly; others may take much longer to be ready to submit a PPR. The SCE proposal would have the effect of running the risk that the later-entering categories would not have any projects able to participate.

There is no ideal solution to this problem. It is, however, reasonable to set the ending date for the bioenergy FiT as being 60 months from the program starting date. This length of time provides a fair opportunity for developers of projects of all types identified under SB 1122 to learn the rules and propose viable projects, while not allowing the price adjustments (leading to price uncertainty) to go on indefinitely.

In practice, this ending date will mean:

1. The IOUs will not longer be required to offer the bioenergy FiT tariff or contract after the end of the 60th month following the first month of the first program period.

2. If an IOU chooses not to offer the bioenergy FiT after the end of the 60th month following the first month of the first program period, no new bidders may enter the queue of that IOU after that date.
3. The bioenergy FiT price will not adjust after the end of the 60th month following the first month of the first program period.
4. Any projects in the queue of any IOU on the last day of the 60th month following the first month of the first program period may have 90 days from that date to execute a contract on the following terms:
   a. The price is the price as it stood for the particular resource category in which the project is bidding on the last day of the 60th month following the first month of the first program period;

   b. The projects will be offered contracts in their order in the queue as it stood on the last day of the 60th month following the first month of the first program period;

   c. The IOU must accept contracts only up to the extent of the capacity remaining in its total capacity allocation for the bioenergy FiT, or two times the IOU's capacity requirement for a program period, whichever is less. (For example, suppose SDG&E has 4 MW of capacity allocation left in the bioenergy FiT, and its capacity offering per program period is 3 MW. It would be required to offer the opportunity for contracts for the lesser of the 4 MW total remaining allocation or 2 * 3 MW.)

5. After the 90-day period, the IOUs may terminate their queues.

It is important to note that because of the different starting times for each program, it is likely that the condition for terminating the general FiT would occur sooner than five years after the beginning of the bioenergy FiT. This circumstance may or may not require that adjustments in the administration of the bioenergy FiT be made. Energy Division staff and the parties are requested to keep this possibility in mind in their ongoing attention to the RPS FiT process.

2.8. Coordination With Other State Agencies

SB 1122 identifies two areas in which the Commission might consult or coordinate with other state agencies specifically in relation to SB 1122.[99] The first, set out in Section 399.20(f)(2)(C), directs the Commission, as part of its implementation of the statute, to coordinate with a specific group of agencies on incentive or subsidy programs for bioenergy.[100] The second, found in Section 399.20(f)(3)(A), provides the list of agencies with which to coordinate on subsidies, and also grants the Commission the option to review the MW allocations for the bioenergy FiT with these agencies to determine if they are appropriate.[101]

Both options for coordination and consultation with the identified state agencies are tasks to be undertaken, if at all, after the bioenergy FiT is established and functioning. The large number and disparate responsibilities of the listed agencies suggest that a significant amount of work on the part of Commission staff would be required simply in order to outline the steps that might be needed

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[99] The Commission's ongoing collaboration with the CEC in the implementation of the RPS is not at issue in these provisions.

[100] Section 399.20(f)(2)(C) provides that, in implementing SB 1122, the Commission shall, among other things:

> Coordinate, to the maximum extent feasible, any incentive or subsidy programs for bioenergy with the agencies listed in subparagraph (A) of paragraph (3) in order to provide maximum benefits to ratepayers and to ensure that incentives are used to reduce contract prices.

[101] Section 399.20(f)(3) (A) provides that:

> The commission, in consultation with the State Energy Resources Conservation and Development Commission, the Sate Air Resources Board, the Department of Forestry and Fire Protection, the Department of Food and Agriculture, and the Department of Resources Recycling and Recovery, may review the allocations of the 250 additional megawatts identified in paragraph (2) to determine if those allocations are appropriate.

to set up such consultations. Actually engaging in the process of coordination on incentive and subsidy programs would require additional research and consultation, as well as information about the use of such incentives, if any, in the segment of the bioenergy generation industry that will participate in the FiT. The Director of Energy Division is authorized to include this topic, if appropriate, in any program forum or similar tool for review of the progress of the bioenergy FiT.

The statutory suggestion of consulting with other agencies on the MW allocations for the bioenergy FiT brings with it the potential for an action item, set out in Section 399.20(3)(B):

> If the commission finds [after review of the MW allocations with the six identified agencies] that the allocations of the 250 additional megawatts identified in paragraph (2) are not appropriate, the commission may reallocate the 250 megawatts among the categories established in subparagraph (A) of paragraph (2).

This is, essentially, an option to redesign a central aspect of the bioenergy FiT. Here, too, much work and experience with the program would be necessary to begin to consider a framework for undertaking such a redesign. The statute commits such a review to the Commission's discretion ("may review"). The Director of Energy Division is authorized to include, if appropriate, in any program forum or similar tool for review of the progress of the bioenergy FiT, the question whether the Commission should undertake such a review in consultation with the other agencies.

2.9. Next Steps

The process for implementing SB 1122 is analogous to that for the initial ReMAT implementation. After issuance of this decision, the IOUs will promptly draft a uniform bioenergy FiT tariff and standard contract, based on the ReMAT

tariff and contract, with the revisions and modifications required by this decision. The IOUs will file and serve the uniform proposed tariff and standard contract, both as a clean copy and as a redline of the current ReMAT tariff and contract. Parties will have the opportunity to comment on the proposal, after which the Commission will issue a decision approving the tariff and standard contract, as proposed or as modified, and any additional or modified rules to implement them. The IOUs will then file the final tariff and contract via advice letter.

Once the bionenergy FiT has been in operation, the Director of Energy Division is directed to investigate, through a workshop or other means, the possibilities for third-party verification of fuel use and/or third-party monitoring of fuel use. Such an investigation should be commenced within six months of the beginning of the first program period.

In order to allow an informed consideration of issues that may arise, at any time after the bioenergy FiT has been in operation for at least a year, the Director of Energy Division is authorized to convene a program forum or undertake similar consultation, to explore issues in the administration and effectiveness of the bioenergy FiT, and to devise proposals for improvements, if relevant.

3. Comments on Proposed Decision

The proposed decision of ALJ Simon in this matter was mailed to the parties in accordance with Section 311 of the Public Utilities Code and comments were allowed under Rule 14.3 of the Commission's Rules of Practice and Procedure. Comments were filed on December 8, 2014 by AECA, BAC, CBD, GPI, PG&E, Placer APCD, SCE, SDG&E, Sustainable Conservation, and TURN. Reply comments were filed on December 15, 2014 by AECA, BAC, CBD, GPI, Phoenix

Energy, PG&E, Placer APCD, SCE, SDG&E, Sustainable Conservation, and TURN.

4. Assignment of Proceeding

Carla A. Peterman is the assigned Commissioner and Anne E. Simon is the assigned ALJ for this portion of this proceeding.

Findings of Fact

1. The term "biogas" is not defined in SB 1122.
2. The term "biogas" is defined in the CEC's *RPS Eligibility Guidebook* (7th edition).
3. The term "municipal organic waste diversion" is not defined in SB 1122.
4. The term "food processing" is not defined in SB 1122.
5. The NAICS classification of "food manufacturing" encompasses the types of activities included within the term "food processing" as used in Section 399.20(f)(2)(A).
6. The term "other agricultural bioenergy" is not defined in SB 1122.
7. The term "sustainable forest management" is not defined in SB 1122.
8. The term "sustainable forest management" does not have a single, widely accepted definition.
9. In D.12-05-035, the Commission exempted all IOUs with fewer than 100,000 service connections in California from participating in the RPS FiT.
10. The statutory mandate of 250 total MW of bioenergy to be procured by PGE, SCE, and SDG&E is required to be allocated according to the ratio of each IOU's peak demand to statewide peak demand.
11. Using only a ratio of each IOU's coincident peak demand to the total system statewide peak demand, the allocations of procurement targets under SB 1122 are: PG&E, 110.78 MW; SCE, 114.53 MW; SDG&E, 24.68 MW.

12. SB 1122 establishes procurement targets by type of bioenergy technology.

13. Resources for fuel for the different bioenergy technologies identified in SB 1122 are not evenly distributed among the service territories of PG&E, SCE, and SDG&E.

14. The statutory allocation among PG&E, SCE, and SDG&E of 50 MW of bioenergy from byproducts of sustainable forest management must be determined based on the proportion of bioenergy that sustainable forest management providers derive from sustainable forest management in fire threat treatment areas, as designated by CAL FIRE.

15. CAL FIRE has formally identified fire threat treatment areas throughout California.

16. It is reasonable to use information about fire threat treatment areas contained in the 2005 report, Biomass Potentials from California Forest and Shrublands Including Fuel Reduction Potentials to Lessen Wildfire Threat, as the basis for allocating the MW to be procured from byproducts of sustainable forest management among the three large IOUs.

17. Based on the fire threat treatment areas identified by CAL FIRE, the allocations for procuring bioenergy from byproducts of sustainable forest management under SB 1122 are: PG&E, 47 MW; SCE, 2.5 MW; SDG&E, 0.5 MW.

18. Due to the uneven distribution of fuel resources identified by SB 1122 among the IOU service territories, the IOUs are likely to face challenges in meeting their procurement target allocations.

19. It is reasonable to use the "hybrid" allocation method put forward in the Staff Proposal to optimize the opportunities for meeting the procurement targets set by SB 1122.

20. Using the allocation method in the Staff Proposal, the allocations for procuring bioenergy from resources identified in Section 399.20(f)(2)(A)(i) and (ii) are as follows:

IOU	Category 1: Biogas	Category 2: Dairy/Ag
PG&E	30.5 MW	33.5 MW
SCE	55.5	56.5
SDG&E	24	0.0

21. Combining the results from the three procurement allocation methodologies (proportion of statewide peak demand; proportion of forest threat treatment area; and "hybrid" allocation of resources identified in Section 399.20(f)(2)(A)(i) and (ii)) produces a reasonable allocation of targets among the IOUs, as follows:

IOU	Biogas	Dairy/Other Ag	Sustainable forest
PG&E	30.5	33.5	47
SCE	55.5	56.5	2.5
SDG&E	24	0.0	0.5

22. It is reasonable to continue to use the methods, structures, terms, and conditions of the current RPS FiT in developing the segment of the FiT for bioenergy projects mandated by SB 1122, except where modification is necessary to facilitate attaining the goals set in SB 1122.

23. In D.12-05-035, as modified by D.13-01-041, the Commission set a single statewide "starting price" for the RPS feed-in tariff mandated by Section 399.20 by taking the weighted average price of the highest executed contracts in one RAM auction.

24. It is reasonable to use an analogous reliance on RAM auctions to set the "starting price" for the bioenergy segment of the feed-in tariff mandated by SB 1122.

25. In the first four RAM auctions, no bids from bioenergy generation facilities eligible for that program (up to 20 MW in size) have received contracts.

26. It is reasonable to use the weighted average of the post-TOD bioenergy bids in the first four RAM auctions as the method for setting the starting price for the bioenergy segment of the FiT.

27. In SB 1122, the Legislature identified and set MW procurement targets for different categories of bioenergy technology.

28. In view of the uneven distribution of the resources for the technology categories set by SB 1122, it is reasonable to allow the FiT price to adjust on a statewide basis, for each technology-based price category.

29. It is reasonable to use the same adjustment frequency of no more than bi-monthly for both the current RPS FiT and the segment of the RPS FiT mandated by SB 1122.

30. It is reasonable to use the same price adjustment increments and cap on the amount of any one price adjustment for both the current RPS FiT and the segment of the RPS FiT mandated by SB 1122.

31. In view of the limited number of bioenergy projects that will initially be available to bid into the bioenergy FiT, it is reasonable to allow the price to adjust when there are a minimum of three eligible bidders statewide in one technology-based price category.

32. It is reasonable to revert to the general RPS FiT requirement of five eligible bidders in a technology-based price category for the price to adjust once a bidder in that technology-based price category of the bioenergy FiT accepts a contract.

33. The fuel and technology characteristics of bioenergy from dairy waste are significantly different from the characteristics of bioenergy from other kinds of agricultural waste.

34. In view of the significant differences between dairy bioenergy and other agricultural bioenergy, it is reasonable to allow the price for dairy bioenergy to adjust separately from the price for other agricultural bioenergy.

35. Resources in some of the technology categories identified in SB 1122, including dairy farms and forest-based resources, are often located far from load centers.

36. The Commission has interpreted the requirement in Section 399.20 that a project must be "strategically located" to participate in the RPS FiT as requiring that the cost of network transmission upgrades when the project interconnects to the distribution system may not exceed $300,000.

37. Interconnecting resources in some of the technology categories identified in SB 1122 at the distribution level is likely to require more than $300,000 in transmission network upgrades in many instances.

Conclusions of Law

1. In order maintain consistency of usage of language for the RPS program between this Commission and the CEC, the definition of "biogas" found in the Glossary of Terms in the CEC's *RPS Eligibility Guidebook* (7th edition) should be used to define "biogas" for purposes of implementing SB 1122.

2. For purposes only of implementing SB 1122, the Commission should define "biogas" as "including digester gas, landfill gas, and any gas derived from a biomass feedstock eligible under the California RPS."

3. In order to provide clarity in the definition of "wastewater treatment," the definition of "wastewater treatment plant" found in Water Code § 13625(b) should be used for purposes of implementing SB 1122.

4. For purposes only of implementing SB 1122, the Commission should define the source of wastewater treatment eligible under SB 1122 as:

> (1) Any facility owned by a state, local, or federal agency and used in the treatment or reclamation of sewage or industrial wastes.
>
> (2) Any privately owned facility used in the treatment or reclamation of sewage or industrial wastes, and regulated by the Public Utilities Commission pursuant to Sections 216 and 230.6 of, and Chapter 4 (commencing with Section 701) of Part 1 of Division 1 of, the Public Utilities Code.
>
> (3) Any privately owned facility used primarily in the treatment or reclamation of sewage for which the state board or a regional board has issued waste discharge requirements.

5. In order to provide clarity and consistency with industry practice, the regulations of the California Integrated Waste Management Board should be used as the basis for the definition of "municipal organic waste diversion" for purposes of implementing SB 1122.

6. For purposes only of implementing SB 1122, the Commission should define "biogas from municipal organic waste diversion" as:

> Biogas that is generated from:
>
> (1) A diversion of organic solid wastes, in accordance with all applicable federal, state and local requirements, from disposal at solid waste landfills or transformation facilities; and,
> (2) Where the organic solid wastes originated from living organisms and their metabolic waste products which contain naturally produced organic compounds, and which are biologically decomposable by microbial and

> fungal action into the constituent compounds of water, carbon dioxide, and other simpler organic compounds; and,
> (3) Where the organic solid wastes were generated by residential, commercial, and industrial sources, or were generated at construction and demolition sites, at food- processing facilities, or at treatment works for water and waste water, and which were collected and transported under the authorization of a jurisdiction or were self- hauled.

7. In order to provide clarity and consistency with industry practice, a definition of the term "food processing" that is based on the NAICS classification of "food manufacturing" should be used for purposes of implementing SB 1122.

8. For purposes only of implementing SB 1122, "food processing" should be defined as:

> Utilizing waste, residue or by-products of food processing or manufacturing facilities, consistent with activities described as "food manufacturing" in Title 311 of the North American Industry Classification System (NAICS). Food processing and manufacturing includes, but is not limited to canning, cooking, roasting, chopping, slicing, cutting, peeling, juicing, milling, fermenting or other processing or manufacturing that changes the form of raw agricultural ingredients into food, or of food into other forms.

9. In order to provide clarity and consistency with industry practice, the definition of "codigestion" for purposes of implementing SB 1122 should clarify that any use of multiple substrates or feedstocks constitutes codigestion.

10. For purposes only of implementing SB 1122, "codigestion" should be defined as:

> use of anaerobic digestion of multiple biodegradable substrates or feedstocks, including but not limited to biosolids, wastewater, animal waste, food scraps, fats, oils, and grease (FOG) or any other suitable organic material.

11. In order to provide clarity and consistency with industry practice, the definition of "dairy bioenergy" for purposes of implementing SB 1122 should preclude the use of any substrate other than dairy waste.

12. For purposes only of implementing SB 1122, "dairy bioenergy" should be defined as " biogas produced solely from the anaerobic digestion of dairy waste."

13. In order to promote clarity and consistency of language usage, the definition of "other agricultural bioenergy" for purposes of implementing SB 1122 should be based on language defining "agricultural power service" in a settlement recently adopted by the Commission in D.13-03-031.

14. For purposes only of implementing SB 1122, "other agricultural bioenergy" should be defined as:

> a bioenergy project that is located on agricultural premises and utilizes the waste, residue or by-products of growing crops, raising livestock or growing horticultural products. Agricultural wastes include, but are not limited to, agricultural crop residues; fruits and vegetables; orchard and vineyard removal; and crop tree and vineyard prunings. Agricultural waste also includes waste, residues and by-products from agricultural drying, hulling, shelling and ginning operations as well as fresh fruit and vegetable packing operations.

15. For purposes only of implementing SB 1122, fire threat reduction activities should be included as an element of sustainable forest management.

16. For purposes only of implementing SB 1122, byproducts of fire threat reduction activities should be defined as:

> Biomass feedstock which originates from fuel reduction activities identified in a fire plan approved by CAL FIRE or other appropriate state, local or federal agency.

17. For purposes only of implementing SB 1122, fire safe clearance activities of government agencies and utilities should be included as an element of sustainable forest management.

18. For purposes only of implementing SB 1122, byproducts of fire safe clearance activities should be defined as:

> Biomass feedstock originating from fuel reduction activities conducted to comply with Pub. Res. Code Sections 4290 and 4291. This would include biomass feedstocks from timber operations conducted in conformance with 14 CCR 1038(c) (150' Fuel Reduction Exemption) as well as projects that fall under 14 CCR 1052.4 (Emergency for Fuel Hazard Reduction), 14 CCR 1051.3-1051.7 (Modified THP [timber harvest plan] for Fuel Hazard Reduction), and 14 CCR 1038(i) (Forest Fire Prevention Exemption), and categorical exclusions on federal lands approved under 36 CFR 220.6(e)(6)ii and (12}-{14).

19. For purposes only of implementing SB 1122, infrastructure clearance projects of government agencies and utilities should be included as an element of sustainable forest management.

20. For purposes only of implementing SB 1122, byproducts of infrastructure clearance projects should be defined as:

> Biomass feedstock derived from 1) fuel reduction activities undertaken by or on behalf of a utility or local, state or federal agency for the purposes of protecting infrastructure, including but not limited to: power lines, poles, towers, substations, switch yards, material storage areas, construction camps, roads, railways; and 2) all utility right-of-way fuel reduction activities undertaken for the purpose of protecting infrastructure, including water conveyance systems (canals, penstocks, flumes, tunnels etc.), gas lines, and telecommunication lines.

21. For purposes only of implementing SB 1122, various additional activities identified in the checklist prepared by staff of CAL FIRE, as revised by this decision and reproduced as Appendix B, as "other sustainable forest management" activities should be included as an element of sustainable forest management.

22. For purposes only of implementing SB 1122, "other sustainable forest management activities" should be identified by the presence of 12 complying answers to the 16 questions on the checklist prepared by staff of CAL FIRE, as revised by this decision, reproduced in Appendix B to this decision.

23. In order to implement the statutory allocations of procurement targets among the IOUs, the following targets should be required for each IOU:

IOU	Biogas	Dairy/Other Ag	Sustainable forest
PG&E	30.5	33.5	47
SCE	55.5	56.5	2.5
SDG&E	24	0.0	0.5

24. In order to maintain consistency among the parts of the RPS FiT program, all IOUs with fewer than 100,000 service connections in California should be exempted from participating in the bioenergy FiT.

25. In order to maintain the integrity of the bioenergy FiT program and promote the development of bioenergy technologies specified by the Legislature, for purposes of implementing SB 1122, generation facilities, with the exception of the "dairy bioenergy" category, should be required to use at least 80% of the fuel resources at the generation facility from the fuel resource category of the facility's contract, measured on an annual basis; any remainder must be sourced from otherRPS-eligible fuel resources identified in SB 1122.

26. In order to maintain the integrity of the bioenergy FiT program and promote the development of bioenergy technologies specified by the Legislature, for purposes of implementing SB 1122, generation facilities in the "dairy bioenergy" technology category should be required to use exclusively dairy waste as the fuel source for the generation facility.

27. In order to maximize the opportunities for participation in the bioenergy FiT, no geographic restrictions on fuel sources should be imposed.

28. In order to promote consistency within the RPS program, the term "commence operation" as used in SB 1122 should be understood to be the same as the term "commercial operations date," as defined by the CEC's *Eligibility Guidebook* in effect at the time a generation facility submits its PPR for the bioenergy FiT.

29. In order to protect ratepayer interests and promote the fair and efficient administration of the RPS FiT, a project should be allowed to enter a bid and maintain a place in the queue in either the bioenergy FiT for those projects under SB 1122, or the general RPS FiT, but not both at the same time.

30. In order to promote opportunities for economies of scale among generation projects eligible under SB 1122, PG&E and SCE should each be required to offer 6 MW of capacity in each bioenergy category in each program period, for any period in which that amount of capacity is available and not subscribed. SDG&E should be required to offer 3 MW of capacity in each bioenergy category in each program period, for any period in which that amount of capacity is available and not subscribed.

31. In order to comply with PURPA, any generation facility seeking a contract under the bioenergy FiT must be a QF in accordance with the rules promulgated by the FERC.

32. In order to comply with the requirements of PURPA and maintain consistency with the ReMAT methodology, the weighted average of the post-TOD bioenergy bids in the first four RAM auctions should be used as the method for setting the starting price for the bioenergy segment of the FiT.

33. In order to take into account the uneven distribution of the resources for the technology categories set by SB 1122 while maintaining a market-based adjusting price, the bioenergy FiT price should adjust on a statewide basis, for each technology-based price category.

34. In order to maintain consistency within the RPS FiT, the bioenergy FiT should use the same price adjustment frequency of no more than bi-monthly as is used in the current RPS FiT.

35. In order to maintain consistency within the RPS FiT, the bioenergy FiT segment should use the same price adjustment increments and cap on the amount of any one price adjustment as is used in the current RPS FiT.

36. In order to take account of the limited number of bioenergy projects that will initially be available to bid into the bioenergy FiT, while maintaining a market-based adjusting price, the price should be allowed to adjust when there are a minimum of three eligible bidders statewide in one technology-based price category.

37. In order to maintain consistency within the RPS FiT, the administration of the bioenergy FiT should revert to the requirement of five eligible bidders in a technology-based price category for the price to adjust once a bidder in that technology-based price category of the bioenergy FiT accepts a contract.

38. In order to take account of the significant differences between dairy bioenergy and other agricultural bioenergy, the price for dairy bioenergy should be allowed to adjust separately from the price for other agricultural bioenergy in the bioenergy FiT.

39. In order to promote the fair and efficient administration of the bioenergy FiT and the goals of SB 1122, the MW allocation for "dairy and other agricultural

bioenergy" category should not be subdivided between the two technology types.

40. In order to promote the fair and efficient administration of the bioenergy FiT, PG&E, SCE, and SDG&E should be required to cooperate in providing information for and administering a statewide "price pool," only for the purpose of determining the offer prices for each price adjustment of the bioenergy FiT.

41. In order to take account of the realities of the technology types identified in SB 1122 , for purposes of the bioenergy FiT only, a generation project should be considered to be "strategically located" as required by Section 399.20 if the cost of network transmission upgrades when the project interconnects to the distribution system does not exceed $300,000, or if the project developer pays any difference between the actual network transmission upgrade costs and $300,000.

42. In order to promote the fair and efficient administration of the RPS FiT and maintain the integrity of the bioenergy FiT, each generation project submitting a PPR should be required to submit both with its PPR and at the time of signing a contract an attestation describing its planned fuel source and its compliance with the fuel source content requirements set out in Conclusions of Law 25 and 26.

43. In order to promote the fair and efficient administration of the RPS FiT and maintain the integrity of the bioenergy FiT, each generation facility with a contract in the bioenergy FiT must provide to the IOU with which it has its contract an annual attestation describing its fuel use for the preceding 12 months and explaining its compliance with the fuel source content requirements set out in Conclusions of Law 25 and 26.

44. In order to promote the fair and efficient administration of the bioenergy FiT, IOUs should be allowed to collect a penalty of $1,000 for every two weeks that a generator is late in submitting the required annual attestation.

45. In order to help maintain the integrity of the bioenergy FiT, an IOU should be allowed to treat an annual report on fuel source that is more than four months late as evidence that the generator is not in compliance with its fuel source maintenance obligations, as set out in Conclusions of Law 25 and 26.

46. In order to maintain the integrity of the bioenergy FiT, if an IOU determines from the generator's annual reports that a generator is not maintaining its fuel source obligations, or its annual attestation is more than four months late, the IOU should be allowed to declare an event of default.

47. In order to maintain the orderly functioning of the SB 1122 bioenergy FiT, in the event that an IOU declares an event of default on the basis of the generator's timely annual attestation on fuel use, the generator should be allowed to cure the default by providing monthly reports that show compliance with fuel use rules for the six consecutive months following the IOU's declaration of an event of default.

48. In order to maximize the opportunity for the development of the bioenergy resources identified in SB 1122 while protecting the interests of ratepayers, the IOUs should be allowed to cease offering the bioenergy FiT after the last day of the 60th month following the first month of the first program period.

49. In order to support the orderly termination of the bioenergy FiT, the price for any technology-based bioenergy price category should be frozen at the price offered on the last day of the 60th month following the first month of the first program period.

50. In order to promote the fair and efficient administration of the bioenergy FiT as it is terminating, the IOUs should be required to allow any project in their respective queues in accordance with their order in the queue, 90 days to take the opportunity to accept a contract at the price in effect on the last day of the 60th month following the first month of the first program period, for an amount of capacity equal to the lesser of all capacity remaining in that IOU's bioenergy FiT allocation, or twice the capacity allocation for a program period.

51. In order to ensure that fuel use complies with the requirements of the bioenergy FiT, the Director of Energy Division should take appropriate steps, commencing not later than six months after the beginning of the first program period, including but not limited to holding a workshop, to explore possible standards and format for third-party verification of fuel sources use by generators in all categories of the bioenergy FiT.

52. The Director of Energy Division should be required to begin an investigation of the operation of the bioenergy FiT at any time that the price for any technology category has hit the price trigger of $197/megawatt-hour (MWh) for two consecutive program periods. The Director of Energy Division should be authorized, but not required, to temporarily suspend the awarding of contracts in any technology category that is under review because the price has hit the price trigger of $197/MWh and remained at that price for two consecutive program periods.

O R D E R

IT IS ORDERED that:

1. Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDG&E) must each procure bioenergy generation in accordance with the following procurement requirements established pursuant to Pub. Util. Code § 399.20(f)(2)(A):

IOU	Biogas	Dairy/Other Agricultural	Sustainable forest management
PG&E	30.5	33.5	47
SCE	55.5	56.5	2.5
SDG&E	24	0.0	0.5

2. Not later than 45 days from the date of this decision, Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company must file and serve joint proposed revisions to the most current ReMAT tariff and standard contract. The joint proposed revised tariff and standard contract must fully implement each and every provision of this decision necessary to modify the existing ReMAT tariff and contract to be suitable as the tariff and standard contract for generation facilities eligible under SB 1122. The proposed revisions must be filed and served in this proceeding or any open proceeding designated as the successor to this proceeding, as both a clean copy and a redline of the current ReMAT tariff and standard contract.

3. Not later than 45 days from the date of this decision, Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company must file and serve a joint proposed form of attestation to be provided by generation facilities as to fuel resource category at the time a generation project submits its program participation request to the utility, in

accordance with the provisions of this decision. The proposed form of attestation must be filed and served in this proceeding or any open proceeding designated as the successor to this proceeding.

4. Not later than 45 days from the date of this decision, Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company must file and serve a joint proposed form of annual attestation to be provided by generation facilities as to fuel resource category during the period the generation facility is in operation, in accordance with the provisions of this decision. The proposed form of attestation must be filed and served in this proceeding or any open proceeding designated as the successor to this proceeding.

5. Not later than 45 days from the date of this decision, Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company must file and serve a joint proposal for the administration of the statewide pool of pricing for the bioenergy feed-in tariff mandated by Senate Bill 1122, in accordance with the provisions of this decision.

6. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company may cease offering the bioenergy feed-in tariff established by this decision after the end of the 60th month after the beginning of the first program period, so long as they allow 90 days for the resolution of bids in their respective bioenergy FiT queues on the last day of the 60th month after the beginning of the first program period.

7. The Director of Energy Division is directed to take appropriate steps, commencing not later than six months after the beginning of the first program period, including but not limited to holding a workshop, to explore possible standards and format for third-party verification of fuel sources use by

generators participating in the bioenergy feed-in tariff pursuant to Pub. Util. Code § 399.20.

8. The Director of Energy Division is required to begin an investigation of the operation of the bioenergy FiT at any time that the price for any technology category has hit the price trigger of $197/megawatt-hour (MWh) for two consecutive program periods. The Director of Energy Division is authorized, but not required, to temporarily suspend the awarding of contracts in any technology category that is under review because the price has hit the price trigger of $197/MWh and remained at that price for two consecutive program periods.

9. The Director of Energy Division is authorized to take appropriate steps, including but not limited to convening a program forum or other mechanism for participation of parties and other market participants, not less than 12 months after the first program period for the bioenergy feed-in tariff pursuant to Pub. Util. Code § 399.20 commences, to evaluate the effectiveness of the tariff and rules set by this decision and, if appropriate, to develop recommendations for improving the fairness, effectiveness, and efficiency of the tariff and rules, and of this Commission's administration of the tariff and rules.

10. Rulemaking 11-05-005 remains open.

This order is effective today.

Dated _____, at San Francisco, California.

Appendix A

Public Utilities Code Section 399.20

APPENDIX A

PUBLIC UTILITIES CODE SECTION 399.20
(Additions made by Senate Bill 1122 are underlined)

Section 399.20

(a) It is the policy of this state and the intent of the Legislature to encourage electrical generation from eligible renewable energy resources.
(b) As used in this section, "electric generation facility" means an electric generation facility located within the service territory of, and developed to sell electricity to, an electrical corporation that meets all of the following criteria:
(1) Has an effective capacity of not more than three megawatts.
(2) Is interconnected and operates in parallel with the electrical transmission and distribution grid.
(3) Is strategically located and interconnected to the electrical transmission and distribution grid in a manner that optimizes the deliverability of electricity generated at the facility to load centers.
(4) Is an eligible renewable energy resource.
(c) Every electrical corporation shall file with the commission a standard tariff for electricity purchased from an electric generation facility. The commission may modify or adjust the requirements of this section for any electrical corporation with less than 100,000 service connections, as individual circumstances merit.
(d) (1) The tariff shall provide for payment for every kilowatthour of electricity purchased from an electric generation facility for a period of 10, 15, or 20 years, as authorized by the commission. The payment shall be the market price determined by the commission pursuant to paragraph (2) and shall include all current and anticipated environmental compliance costs, including, but not limited to, mitigation of emissions of greenhouse gases and air pollution offsets associated with the operation of new generating facilities in the local air pollution control or air quality management district where the electric generation facility is located.
(2) The commission shall establish a methodology to determine the market price of electricity for terms corresponding to the length of contracts with an electric generation facility, in consideration of the following:
(A) The long-term market price of electricity for fixed price contracts, determined pursuant to an electrical corporation's general procurement activities as authorized by the commission.
(B) The long-term ownership, operating, and fixed-price fuel costs associated with fixed-price electricity from new generating facilities.
(C) The value of different electricity products including baseload, peaking, and as-available electricity.

(3) The commission may adjust the payment rate to reflect the value of every kilowatthour of electricity generated on a time-of-delivery basis.
(4) The commission shall ensure, with respect to rates and charges, that ratepayers that do not receive service pursuant to the tariff are indifferent to whether a ratepayer with an electric generation facility receives service pursuant to the tariff.
(e) An electrical corporation shall provide expedited interconnection procedures to an electric generation facility located on a distribution circuit that generates electricity at a time and in a manner so as to offset the peak demand on the distribution circuit, if the electrical corporation determines that the electric generation facility will not adversely affect the distribution grid. The commission shall consider and may establish a value for an electric generation facility located on a distribution circuit that generates electricity at a time and in a manner so as to offset the peak demand on the distribution circuit.
(f) (1) An electrical corporation shall make the tariff available to the owner or operator of an electric generation facility within the service territory of the electrical corporation, upon request, on a first-come-first-served basis, until the electrical corporation meets its proportionate share of a statewide cap of 750 megawatts cumulative rated generation capacity served under this section and Section 387.6. The proportionate share shall be calculated based on the ratio of the electrical corporation's peak demand compared to the total statewide peak demand.
(2) By June 1, 2013, the commission shall, in addition to the 750 megawatts identified in paragraph (1), direct the electrical corporations to collectively procure at least 250 megawatts of cumulative rated generating capacity from developers of bioenergy projects that commence operation on or after June 1, 2013. The commission shall, for each electrical corporation, allocate shares of the additional 250 megawatts based on the ratio of each electrical corporation's peak demand compared to the total statewide peak demand. In implementing this paragraph, the commission shall do all of the following:
(A) Allocate the 250 megawatts identified in this paragraph among the electrical corporations based on the following categories:
(i) For biogas from wastewater treatment, municipal organic waste diversion, food processing, and codigestion, 110 megawatts.
(ii) For dairy and other agricultural bioenergy, 90 megawatts.
(iii) For bioenergy using byproducts of sustainable forest management, 50 megawatts. Allocations under this category shall be determined based on the proportion of bioenergy that sustainable forest management providers derive from sustainable forest management in fire threat treatment areas, as designated by the Department of Forestry and Fire Protection.
(B) Direct the electrical corporations to develop standard contract terms and conditions that reflect the operational characteristics of the projects, and to provide a streamlined contracting process.
(C) Coordinate, to the maximum extent feasible, any incentive or subsidy programs for bioenergy with the agencies listed in subparagraph (A) of paragraph (3) in order to

provide maximum benefits to ratepayers and to ensure that incentives are used to reduce contract prices.
(D) The commission shall encourage gas and electrical corporations to develop and offer programs and services to facilitate development of in-state biogas for a broad range of purposes.
(3) (A) The commission, in consultation with the State Energy Resources Conservation and Development Commission, the State Air Resources Board, the Department of Forestry and Fire Protection, the Department of Food and Agriculture, and the Department of Resources Recycling and Recovery, may review the allocations of the 250 additional megawatts identified in paragraph (2) to determine if those allocations are appropriate.
(B) If the commission finds that the allocations of the 250 additional megawatts identified in paragraph (2) are not appropriate, the commission may reallocate the 250 megawatts among the categories established in subparagraph (A) of paragraph (2).
(4) For the purposes of this subdivision, "bioenergy" means biogas and biomass.
(g) The electrical corporation may make the terms of the tariff available to owners and operators of an electric generation facility in the form of a standard contract subject to commission approval.
(h) Every kilowatthour of electricity purchased from an electric generation facility shall count toward meeting the electrical corporation's renewables portfolio standard annual procurement targets for purposes of paragraph (1) of subdivision (b) of Section 399.15.
(i) The physical generating capacity of an electric generation facility shall count toward the electrical corporation's resource adequacy requirement for purposes of Section 380.
(j) (1) The commission shall establish performance standards for any electric generation facility that has a capacity greater than one megawatt to ensure that those facilities are constructed, operated, and maintained to generate the expected annual net production of electricity and do not impact system reliability.
(2) The commission may reduce the three megawatt capacity limitation of paragraph (1) of subdivision (b) if the commission finds that a reduced capacity limitation is necessary to maintain system reliability within that electrical corporation's service territory.
(k) (1) Any owner or operator of an electric generation facility that received ratepayer-funded incentives in accordance with Section 379.6 of this code, or with Section 25782 of the Public Resources Code, and participated in a net metering program pursuant to Sections 2827, 2827.9, and 2827.10 of this code prior to January 1, 2010, shall be eligible for a tariff or standard contract filed by an electrical corporation pursuant to this section.
(2) In establishing the tariffs or standard contracts pursuant to this section, the commission shall consider ratepayer-funded incentive payments previously received by the generation facility pursuant to Section 379.6 of this code or Section 25782 of the Public Resources Code. The commission shall require reimbursement of any funds received from these incentive programs to an electric generation facility, in order for that facility to be eligible for a tariff or standard contract filed by an electrical

corporation pursuant to this section, unless the commission determines ratepayers have received sufficient value from the incentives provided to the facility based on how long the project has been in operation and the amount of renewable electricity previously generated by the facility.
(3) A customer that receives service under a tariff or contract approved by the commission pursuant to this section is not eligible to participate in any net metering program.
(l) An owner or operator of an electric generation facility electing to receive service under a tariff or contract approved by the commission shall continue to receive service under the tariff or contract until either of the following occurs:
(1) The owner or operator of an electric generation facility no longer meets the eligibility requirements for receiving service pursuant to the tariff or contract.
(2) The period of service established by the commission pursuant to subdivision (d) is completed.
(m) Within 10 days of receipt of a request for a tariff pursuant to this section from an owner or operator of an electric generation facility, the electrical corporation that receives the request shall post a copy of the request on its Internet Web site. The information posted on the Internet Web site shall include the name of the city in which the facility is located, but information that is proprietary and confidential, including, but not limited to, address information beyond the name of the city in which the facility is located, shall be redacted.
(n) An electrical corporation may deny a tariff request pursuant to this section if the electrical corporation makes any of the following findings:
(1) The electric generation facility does not meet the requirements of this section.
(2) The transmission or distribution grid that would serve as the point of interconnection is inadequate.
(3) The electric generation facility does not meet all applicable state and local laws and building standards and utility interconnection requirements.
(4) The aggregate of all electric generating facilities on a distribution circuit would adversely impact utility operation and load restoration efforts of the distribution system.
(o) Upon receiving a notice of denial from an electrical corporation, the owner or operator of the electric generation facility denied a tariff pursuant to this section shall have the right to appeal that decision to the commission.
(p) In order to ensure the safety and reliability of electric generation facilities, the owner of an electric generation facility receiving a tariff pursuant to this section shall provide an inspection and maintenance report to the electrical corporation at least once every other year. The inspection and maintenance report shall be prepared at the owner's or operator's expense by a California-licensed contractor who is not the owner or operator of the electric generation facility. A California-licensed electrician shall perform the inspection of the electrical portion of the generation facility.

(q) The contract between the electric generation facility receiving the tariff and the electrical corporation shall contain provisions that ensure that construction of the electric generating facility complies with all applicable state and local laws and building standards, and utility interconnection requirements.
(r) (1) All construction and installation of facilities of the electrical corporation, including at the point of the output meter or at the transmission or distribution grid, shall be performed only by that electrical corporation.
(2) All interconnection facilities installed on the electrical corporation's side of the transfer point for electricity between the electrical corporation and the electrical conductors of the electric generation facility shall be owned, operated, and maintained only by the electrical corporation. The ownership, installation, operation, reading, and testing of revenue metering equipment for electric generating facilities shall only be performed by the electrical corporation.

END OF APPENDIX A

APPENDIX B

SB 1122 Forest Biomass

SB1122 Forest Biomass
Forest Biomass Sustainability Byproduct Eligibility Form:
Instructions and Worksheet

Instructions

Projects which fall into the Fire Threat and categories as defined are presumed to be eligible and are not required to fill out the form.

With the exception of projects types noted below, forest management activities not associated with forest biomass categories "i", "ii", and "iii", referenced below, will require use of the Forest Biomass Sustainability Byproduct Eligibility Form to determine if the biomass generated by the project is eligible under PUC 399.20.

Section I

Complete each item with full information

Ownership Category: identify if the parcel on which the project is conducted is owned by a private entity, the state or the Federal Government.
Number of Acres: Identify how many acres are being treated / harvested by the project
Type of Harvest Document (If applicable): Identify the type of harvest document, State Permit, Federal Permit or exemption that apply to this project
Harvest Document Designator: Identify the State or Federal entity that issued the harvest permit, exemption or other document that applicable to this project
Facility Identifier: Provide the identifier for the SB1122 (or other) forest biomass facility which will receive and utilize the forest waste (biomass) to generate energy.

Section II

To qualify under forest biomass category "iv", treatment activities must provide co-benefits for at least 12 of the 16 items identified in Sections A- E below. In addition, at least one item must come from each of Sections A- D.
A Registered Professional Forester should determine if planned activities meet the sustainability criteria under section 2.2.3.4 of the California Public Utilities Commission Decision Implementing Senate Bill 1122.

Forest Biomass Sustainability Byproduct Eligibility Form

Note: Please keep responses brief (under 250 words) and focused on the basis for the determination that the project will support sustainability of the specific objective. In lieu of providing a written response or in addition to the written response, where appropriate provide source references to the approved harvest/NEPA document where discussion of potential significant adverse impacts, evaluation and mitigation measures are provided.

A. Habitat Temporal and Spatial Diversity Objectives (Pick all that apply)

1. Openings for shade intolerant species were created to promote regeneration and habitat diversity.
   Please describe percent and distribution of areas in small openings less than 2.5 acres in size and planned regeneration methods:

2. Multi-age, multi-species tree habitats were created at the project level.
   Please describe how the project immediately post harvest will support maintenance, enhancement and/or restoration of canopy cover and maintain or increase the QMD of an overstory of multi-age, multi-species tree habitat.

3. Understory vegetation was retained and distributed across the project site consistent with fire threat reduction and habitat objectives and contributes to spatial heterogeneity by varying treatments to retain untreated patches, openings, and widely spaced single trees and clumps.
   Please describe objectives for retention of understory shrubs and trees and estimate post harvest areas of untreated patches and openings.

B**. Habitat Elements: (Pick all that apply)**

4. Snags are retained consistent with safety, FPRs, and fire threat reduction goals.
   Please describe post harvest snag retention objectives and estimate the percentage of existing snags to be removed as part of the planned forest management activities.

5. Down logs with benefit to habitat diversity are retained consistent with fire threat reduction goals.

   Please describe project treatment objectives for retention of existing or project related down woody material.

6. Large hardwoods and legacy trees are retained as post treatment stand components and habitat.
   Please describe post harvest retention objectives for hardwoods and legacy trees.

7. Management practices and harvesting associated with the project impacts are consistent with objectives of retaining or recruiting large trees at the project and landscape level.
   Please describe post harvest old growth tree retention objectives.

C. Forest Health and, Fire Management Objectives: (Pick all that apply)

8. Fire threat is reduced through treatment of ladder fuels and surface fuels to achieve reduction in incidence of crown torching in overstory trees and to avoid active crown fires under most conditions.
   Please describe post harvest spatial arrangement objectives for retention of understory shrubs and trees in relation to overstory trees.

9. Outcomes support reintroduction of prescribed fire.
   Please describe, if applicable, post harvest surface and ladder fuel conditions and proposed use of prescribed fire.

10. Improvement of overall forest health through reduction in overstocking in small treesizes and reduction of competition for soil moisture with overstory trees.
    Please describe.

D. Air and Water Quality Protection: (Pick all that apply)

11. Avoided emissions by eliminating need for open burning of slash piles and/or decomposition.
    Please describe the relative reduction in emissions attributable to removal of material from the project site for use as fuel for energy generation in comparison to piling and burning or piling and decomposition.

12. Measures have been incorporated to address moist microsites, and near stream habitats.
    Please describe what measures will be employed to protect moist microsites and near-stream habitats.

13. Soil protection measures used to minimize compaction and loss of A-horizons and soil carbon.
    Please describe.

14. Operational plans provide for the retention of fine woody debris to minimize potential threats to soil productivity (and meet fire threat reduction objectives).
    Please describe.

E. Societal and Economic Benefits: (Pick all that apply)

15. Project contributes to societal benefits of local communities by way of fire safety,improved environmental health and overall quality of life.
    Please describe.

16. Project contributes to local economies by way of providing additional to local employment opportunities and investment.
    Please describe.

(END OF APPENDIX B)

APPENDIX C

Overview of the ReMAT Pricing Mechanism

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Overview of the ReMAT Pricing Mechanism

Pursuant to D.12-05-035, D.13-01-041, and D.13-05-034, generators interested in participating in the FiT program must first meet the program's minimum project viability criteria. The generator then must submit a program participation request (PPR) to the utility. Upon receipt of the PPR, the utility places the generator in the ReMAT Queue, which is formed on a first-come, first-served basis for each product type available within the program and based on the time/date that a generator submits its completed PPR.

Under the terms of the program, the utility offers FiT contracts every two months to generators in the ReMAT Queue until the authorized capacity allocation for that two-month period has been subscribed/accepted by generators. The offer price is set by the ReMAT pricing mechanism. Under the ReMAT pricing mechanism, the utilities offered a starting ReMAT price of $89.23/MWh on November 1, 2013 (the launch date) for each of the following three product types: peaking as-available; non-peaking as-available; and baseload.[102] This price stayed constant for two months. The offer price remains fixed for the term of the contract. If a generator declines to accept the offer price, it maintains its position in the ReMAT Queue for next program period.[103]

SCE and PG&E offer 5 MW for each product type, for each two-month program period. SDG&E offers 3 MW.[104]

At the expiration of this two month period, the ReMAT price is subject to a price adjustment, for each product type (for each utility), based on market subscription levels at the previously offered price during the prior two month period. As a result, the ReMAT price offered for each product type diverged after the initial two-month period, as the price adjusts to market conditions.

The price adjustment will only be triggered if there are at least five eligible projects from different developers in the ReMAT Queue for a particular product

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[102] D.12-05-035, Section 6.3, at 42-44.

[103] D.12-05-035, Section 6.4, at 45.

[104] D.13-05-034, Section 4.1, at 12.

type.[105] If that condition is met, then the ReMAT price will be subject to adjustment based on the following:[106]

Price Increase:

If the capacity subscribed at the offered ReMAT price is **less than 20%** of the capacity offered for that program period, then the price will increase the following program period. If these conditions are met for consecutive program periods, the price will increase by the following increments:

- **First adjustment:** $89.23/MWh **+ $4/MWh**
- **Second consecutive adjustment:** $93.23/MWh **+ $8/MWh**
- **Third consecutive adjustment:** $101.23/MWh **+ $12/MWh**
- **Fourth consecutive adjustment:** $113.23/MWh **+ $12/MWh**

The maximum price increase for any period is capped at $12/MWh. Additionally, if the conditions for a price increase are not met during a given program period, then the next time that a price increase is triggered, the increment of that increase will reset to +$4/MWh.

Price Decrease:

If a sufficient number of generators accept the offered ReMAT price such that offering contracts to all willing generators would result in subscription of 100% of the capacity offered for that program period, then the price will decrease the following program period.[108] If these conditions are met for consecutive program periods, the price will decrease by the following increments:

- **First adjustment:** $89.23/MWh **- $4/MWh**

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[105] D.12-05-035, Section 6.4, at 45.

[106] D.13-05-034, Section 4.1, at 12-15.

[108] Note that, pursuant to D.13-05-034, the utility is not obligated to award FiT contracts to generators beyond its monthly capacity allocation (5 MW for SCE and PG&E, and 3 MW for SDG&E). As a result, if the project that is next in the ReMAT Queue indicates that it would accept the offered ReMAT price, but doing so would exceed the utility's capacity allocation for that period, then the utility need not award that contract. The 100% threshold described here for a price decrease would be triggered, and that generator would be required to wait until the next period.

- **Second consecutive adjustment:** $85.23/MWh **- $8/MWh**
- **Third consecutive adjustment:** $77.23/MWh **- $12/MWh**
- **Fourth consecutive adjustment:** $65.23/MWh **- $12/MWh**

The maximum price decrease for any period is capped at $12/MWh. Additionally, if the conditions for a price decrease are not met during a given program period, then the next time that a price decrease is triggered, the increment of that decrease will reset to -$4/MWh.

No Price Change:

If for any program period the number of eligible projects from different developers in the ReMAT Queue drops below five, then the price will remain the same and will not adjust. Alternatively, if there are at least five eligible projects from different developers in the ReMAT Queue, but the conditions for a price increase or decrease are not met, then the price will also remain the same.

Under the current FiT Program, the ReMAT pricing mechanism operates independently to determine the market price for each of three product types: peaking, as-available, and baseload.[109] The ReMAT mechanism sets the market price separately for each utility, for each of these three product types.

(END OF APPENDIX C)

[109] Section 399.20(d)(2)(C) provides that " the commission shall establish a methodology to determine the market price of electricity . . . in consideration of the following: the value of different electricity products including baseload, peaking, and as-available electricity…."