# ATTACHMENT A

CONFORMED VERSION OF D.12-05-035

Decision 12-05-035, as modified by Decision 13-01-041

**BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA**

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

# DECISION REVISING FEED-IN TARIFF PROGRAM, IMPLEMENTING AMENDMENTS TO PUBLIC UTILITIES CODE SECTION 399.20 ENACTED BY SENATE BILL 380, SENATE BILL 32, AND SENATE BILL 2 1X AND DENYING PETITIONS FOR MODIFICATION OF DECISION 07-07-027 BY SUSTAINABLE CONSERVATION AND SOLUTIONS FOR UTILITIES, INC.

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Attachment A - 10-day reporting requirement to tariffs under the § 399.20 FiT Program R.11-05-005

**DECISION REVISING FEED-IN TARIFF PROGRAM, IMPLEMENTING AMENDMENTS TO PUBLIC UTILITIES CODE SECTION 399.20 ENACTED BY SENATE BILL 380, SENATE BILL 32, AND SENATE BILL 2 1X AND DENYING PETITIONS FOR MODIFICATION OF DECISION 07-07-027 BY SUSTAINABLE CONSERVATION AND SOLUTIONS FOR UTILITIES, INC.**

## 1. Summary

Today's decision implements the amendments to Pub. Util. Code § 399.20[1] enacted by Senate Bill (SB) 380 (Kehoe, Stats. 2008, ch. 544, § 1), SB 32 (Negrete McLeod, Stats. 2009, ch. 328, § 3.5), and the more recent amendments enacted by SB 2 of the 2011-2012 First Extraordinary Session (Simitian, Stats. 2011, ch. 1) (SB 2 1X).

Notably, in implementing the statutory amendments to § 399.20, this decision adopts, among other things, a new pricing mechanism for the Commission's § 399.20 Feed-in Tariff (FiT) Program. This new pricing mechanism will be referred to as the "Renewable Market Adjusting Tariff" or "Re-MAT." Re-MAT includes two principal components. First, a starting price based on the weighted average contract price of Pacific Gas and Electric Company, Southern California Electric Company, and San Diego Gas & Electric Company's highest priced executed contract resulting from the Commission's Renewable Auction Mechanism auction held in November 2011. This starting price will apply to three FiT product types: baseload, peaking as-available, and non-peaking as-available.[2] Second, we adopt a two-month price adjustment

[1] All statutory references are to the Public Utilities Code unless otherwise indicated.

[2] The term "as-available" is used interchangeably with the term "intermittent."

mechanism that may increase or decrease the price for each product type every two months based on the market response. Finally, each accepted project will be paid a time-of-delivery adjustment based on the generator's actual energy delivery profile and the individual utility's time-of-delivery factors.

Today's decision also adopts several new or revised FiT Program components, including, among other things, increasing the maximum size of eligible facilities to 3 megawatts, adjusting capacity allocations among the utilities, adopting project viability criteria, and excluding small electric utilities from the program.

Lastly, this decision denies two petitions for modification of Decision 07-07-027, the decision initially establishing the tariffs and standard contracts for utilities under § 399.20, filed by Sustainable Conservation and by Solutions for Utilities, Inc.

This proceeding remains open.

## 2. Background

Today's decision focuses on implementing those aspects of the Renewables Portfolio Standard Program (RPS Program) under § 399.11 *et seq*. relevant to smaller renewable generation projects commonly referred to as distributed generation. Specifically, today's decision focuses on § 399.20.[3] This code section declares the Legislature's intent and the policy of the state to encourage electrical generation from small distributed generation that qualifies as "eligible renewable

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[3] All references to § 399.20 are to that section as amended by Senate Bill (SB) 380 (Stats. 2008, Ch.544), SB 32 (Stats. 2009. Ch.328), and SB 2 1X (2011-2012 First Extraordinary Session, Stats. 2011, Ch.1) unless otherwise noted.

energy resources" under the RPS Program with an effective capacity of 3 megawatts (MW) or less and, among other things, strategically located on the distribution grid.[4] Today's decision refers to the Commission's ongoing implementation work under § 399.20 as the § 399.20 Feed-in Tariff (FiT) Program.

### 2.1. Legislative History – § 399.20

In 2002, the Legislature enacted SB 1078 (Sher, Stats. 2002, ch. 516), to be effective on January 1, 2003, to establish the RPS Program (Article 16, commencing with § 399.11, of the Pub. Util. Code) and to, among other things, increase the amount of electricity procured per year from eligible renewable energy resources, as defined therein, to an amount that equaled at least 20% of the total electricity sold to retail customers in the state by December 31, 2017. The Legislature accelerated this goal to 20% by 2010 in SB 107 (Simitian, Stats. 2006, ch. 464). In 2011, the Legislature extended and increased the state's goal under the RPS Program to 33% of the total electricity sold to retail customers in the state by December 31, 2020.[5]

The code section relevant to today's decision, § 399.20, was initially added to the Pub. Util. Code by Assembly Bill (AB) 1969 (Yee, Stats. 2006, ch. 731), to be effective on January 1, 2007. The provisions of § 399.20 are part of the RPS Program and, importantly, under § 399.20, every kilowatt hour (kWh) of electricity purchased from an electric generation facility counts toward meeting

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[4] *See* § 399.20(a) and (b)(1)-(4).

[5] *See generally*, SB 2 1X.

an electric corporation's RPS Program procurement quantity requirements under SB 2 1X of 33% by 2020.[6]

As initially enacted by AB 1969, § 399.20 created the renewable FiT Program. This program has since been expanded by the Legislature and the Commission. Under AB 1969, electrical corporations were required to make a tariff or standard contract available only to public water and wastewater customers on a first-come, first-served basis until the electrical corporation met its proportionate share of a 250 MW statewide procurement limit.

Since 2007, the Legislature has adopted several amendments to this code section, including SB 380, SB 32, and SB 2 1X, and the Commission has adopted Decision (D.) 07-07-027, implementing the Commission's § 399.20 FiT Program as set forth in AB 1969. Today's decision builds upon D.07-07-027 by modifying the Commission's existing § 399.20 FiT Program. Specifically, today's decision addresses the amendments to § 399.20 enacted by SB 380, SB 32, and SB 2 1X.[7]

The amendments to § 399.20 set forth in SB 380, SB 32, and SB 2 1X cover a broad range of issues, including increasing the maximum project size to 3 MW

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[6] More details regarding the RPS Program's compliance periods and quantity requirements under SB 2 1X are set forth in D.11-12-020 (*Decision Setting Procurement Quantify Requirements for Retail Sellers for the Renewables Portfolio Standard Program*).

[7] SB 380 was enacted by the Legislature in September 2008 to be effective January 1, 2009; SB 32 was enacted by the Legislature in 2009 to be effective January 1, 2010, and SB 2 1X was enacted by the Legislature in 2011 to be effective on December 10, 2011. SB 2 1X, enacted in the 2011-2012 First Extraordinary Session of the Legislature, went into effect on the 91st day after adjournment of the special session at which the bill was passed. (Gov't. Code § 9600(a).) The 2011-2012 First Extraordinary Session adjourned on September 10, 2011, making SB 2 1X effective on December 10, 2011.

from 1.5 MW. Some of the most controversial issues relate to price. Many of these provisions must be memorialized in a contract, also referred to as a power purchase agreement, between the utility and the generator. We will address some of the terms of these contracts under § 399.20, as amended, in today's decision. More specific terms and conditions will be addressed in a subsequent decision in this proceeding, which will focus exclusively on the Commission's adoption of a single standard form contract for the § 399.20 FiT Program.[8] We also note that generation projects seeking to participate in the § 399.20 FiT Program must enter into an interconnection agreement. We will address some of the interconnection issues referred to in § 399.20, as amended, in today's decision. However, the majority of the issues related to interconnection under the § 399.20 FiT Program will be addressed in a separate, ongoing Commission proceeding , Rulemaking (R.) 11-09-011,[9] which, among other things, "seeks to

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[8] *See, Joint Assigned Commissioner's and Administrative Law Judge's Ruling Setting Workshop on a Utility Standard Form Contract for the Section 399.20 Feed-In Tariff Program, dated January 10, 2012* (This ruling directed the utilities to collaborate to create one uniform contract for the program. The Commission held a workshop to review the contract on February 22, 2012 and will address this matter in a subsequent decision.) All rulings and pleadings filed in this proceeding are available at the "Docket Card" link for this rulemaking at www.cpuc.ca.gov.

[9] R.11-09-011, *Order Instituting Rulemaking on the Commission's own motion to improve distribution level interconnection rules and regulations for certain classes of electric generators and electric storage resources* (adopted on September 22, 2012). A proposed settlement was filed in the interconnection proceeding on March 16, 2012 that offers a consensus-based reform of Electric Rule 21, the interconnection tariff under this Commission's jurisdiction. The complete *Motion for Approval of Settlement Agreement Revising Distribution level Interconnection Rules and Regulations,* including the proposed revised

*Footnote continued on next page*

review, and if necessary revise Rule 21 to ensure that the interconnection process is timely, non-discriminatory, cost-effective, and transparent."[10]

### 2.2. Feed-In Tariff Program - Decision 07-07-027

The Commission implemented AB 1969 in 2007 through D.07-07-027 for eligible facilities up to 1.5 MW. Although § 399.20 only applied to a narrowly defined group of customers, specifically public water and wastewater facilities, D.07-07-027 extended the program under § 399.20 to a broader group of eligible customers in Pacific Gas and Electric Company's (PG&E) and Southern California Edison Company's (SCE) service territories. D.07-07-027 directed San Diego Gas & Electric Company (SDG&E), PG&E, and SCE to file tariffs with a fixed price for public water and wastewater facilities and, in addition, directed PG&E and SCE to file similar tariffs for all customers in their service territories. Approximately a year later, in D.08-09-033, the Commission directed SDG&E to file a tariff extending § 399.20 to all customers in its service territory.

Consistent with the then-existing statutory requirements under AB 1969, then codified in § 399.20(5)(d), D.07-07-027 adopted the Market Price Referent (MPR) as the § 399.20 FiT Program price. The MPR was designed by the Commission to reflect the long-term ownership, operating, and fixed-price fuel costs for a new 500 MW natural gas-fired combined cycle gas turbine.[11] The MPR

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Rule 21, is available at [http://docs.cpuc.ca.gov/EFILE/MOTION/162852.PDF](http://docs.cpuc.ca.gov/EFILE/MOTION/162852.PDF). The Commission is presently considering the proposed settlement.

[10] R.11-09-011 at 2.

[11] The Commission set the initial parameters for the MPR in D.03-06-071. The method for calculating the MPR was first developed in D.04-06-015. In D.05-12-042, the

*Footnote continued on next page*

calculates a levelized price for a proxy baseload combined cycle gas turbine using a cash flow modeling approach. The inputs for the MPR model include installed capital costs, fixed and variable operations and maintenance costs, natural gas fuel costs, cost of capital, and environmental permitting and compliance costs. The model produces several MPR values based on a facility's online date and contract term length (e.g., 10, 15, or 20 years). Under the Commission's adopted methodology, the appropriate MPR value for a particular RPS project is adjusted to account for the value of different electricity products (e.g., baseload, peaking, and as-available) by applying the individual utility's time-of-delivery factors.

Starting in 2004, the Commission has calculated a MPR for each RPS solicitation.[12] The Commission's most recently calculated and adopted MPR, referred to as the 2011 MPR, is found in Resolution E-4442 (issued on December 6, 2011).[13] In terms of pricing for the FiT Program under the MPR, the 2011 MPR, for example, would pay a generator that came online in 2013 with a 20-year contract at $93.75 per megawatt hour (MWh) pre time-of-delivery adjustments. Among other things, Resolution E-4442 ordered each utility to

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methodology for calculating the MPR was expanded and stabilized. The Commission subsequently updated the MPR methodology in D.08-10-026.

[12] R.04-04-026, *Assigned Commissioner's Ruling Disclosing Market Price Referents for the Renewables Portfolio Standard Program*, dated February 11, 2005.

[13] Resolution E-4442 provides "the adopted 2011 MPR values establish the prices, effective January 3, 2011, for the renewable energy FiT program set forth in Public Utilities Code section 399.20."

update its tariffs for the § 399.20 FiT Program, as required by D.07-07-027, consistent with the 2011 MPR.[14]

Utilities filed tariffs adopting the 2011 MPR as the price for their § 399.20 FiT Program on or about December 8, 2011.[15] These December tariff filings reduced the prices under the FiT Program from, for example, $108.98/MWh to $93.75/MWh pre time-of-delivery adjustments for a generator that came online in 2013 with a 20-year contract.[16] These recently filed tariffs are the effective prices for the existing FiT Program until modified by this decision and any related tariff filings by the utilities.

### 2.3. Rulemaking 11-05-005

This proceeding, R.11-05-005, succeeds R.08-08-009 and incorporates the entire record of R.08-08-009. More than 40 parties filed comments to the Commission's Order Instituting Rulemaking for R.11-05-005 on May 31, 2011 and

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[14] Ordering Paragraph 2 of Resolution E-4442 provides as follows: "Each electric corporation obligated under Decision 07-07-027, pursuant to Public Utilities Code Section 399.20, shall file a Tier 1 advice letter updating its relevant tariffs and standard contracts with the 2011 market price referent. The advice letter shall be filed and served within 7 days of the effective date of this resolution. The advice letter will have an effective date of January 3, 2012."

[15] These filings include Advice Letters 2310-E (SDG&E), 3964-E (PG&E), 2670-E (SCE), 13-E (California Pacific Electric Company, LLC), 460-E (PacifiCorp dba Pacific Power), and 261-E (Bear Valley Electric Service).

[16] The 2011 MPR is lower than the 2009 MPR due, primarily, to a drop in natural gas prices from 2009 to 2011. Approximately 75% of the MPR calculation is driven by the price of natural gas. The 2011 MPR superseded the 2009 MPR because the Commission did not calculate an MPR in 2010. As a result, the 2009 MPR continued to be effective until the issuance of Resolution E-4442.

June 9, 2011. An initial prehearing conference regarding amendments to the FiT Program was held on June 13, 2011. The assigned Commissioner issued a scoping memo ruling pursuant to Rule 7.3 of the Commission's Rules of Practice and Procedure on July 8, 2011.

The scoping memo ruling noted that SB 2 1X made significant changes to the overall RPS Program and identified the four "highest priority" issues for immediate attention in the Commission's implementation of SB 2 1X. One of these four issues is the Commission's implementation of the amendments to § 399.20, as set forth in SB 32 and SB 2 1X, and applicable to the FiT Program. Parties provided substantial input to the Commission on the topic of § 399.20 and the amendments thereto. Parties filed briefs in March 2011 in the predecessor proceeding, R.08-08-009. These briefs were filed in response to a ruling by the Administrative Law Judge (ALJ) entitled, *ALJ's Ruling Regarding Setting Schedule for Briefs on Implementation of Senate Bill 32*, dated January 27, 2011. In July and August 2011, parties filed further comments on the § 399.20 FiT Program in response to the *ALJ's Ruling Setting Forth Implementation Proposal for SB 32 and SB 2 1X Amendments to Section 399.20*, dated June 27, 2011. Then, the Commission's Energy Division Staff issued a proposal on pricing and other aspects of § 399.20, which was subsequently entered into the record and commented upon by parties. In today's decision, we refer to this October 13, 2011 Staff Proposal as the "Renewable FiT Staff Proposal."

Taking into consideration the record of this proceeding, consisting of party briefs, comments, the Renewable FiT Staff Proposal, and other evidence, we implement the provisions of § 399.20, as amended.

## 3. Parameters in Implementing the § 399.20 Feed-In Tariff Program, as Amended

In implementing the amendments to the § 399.20 FiT Program, we rely on federal law, specifically, avoided cost requirements under the Public Utility Regulatory Policies Act of 1978 (PURPA).[17] We also rely upon § 399.20 and state laws governing statutory construction. In addition, we rely on the policy guidelines set forth in the June 27, 2011 ALJ ruling.

### 3.1. Federal Law – Avoided Cost

In implementing § 399.20, as amended, we necessarily comply with the provisions of the Federal Power Act § 205 and § 206, which grant exclusive jurisdiction to the Federal Energy Regulatory Commission (FERC) to regulate wholesale sales of electricity in interstate commerce.

The primary exception to FERC's authority over wholesale rates is established by PURPA. PURPA authorizes state public utilities commissions to establish the wholesale rate, as long as it is an avoided cost for utilities' wholesale purchases from Qualifying Facilities (QFs).[18] FERC gives wide latitude to state public utilities commissions in defining the avoided cost of generation. In general, QFs are alternative energy power production facilities that are primarily renewable or gas-fired cogeneration units.[19]

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

[18] *See* 16 U.S.C. § 824a-3(b); 18 C.F.R. § 292.304(a)(2).

[19] *See* 18 C.F.R. § 292.304(a).

The modifications to the § 399.20 FiT Program adopted today comply with federal law by requiring, among other things, that all FERC jurisdictional generators[20] participating in the program register with the FERC as QFs[21] and by adopting a price consistent with PURPA, including the most recent guidance provided by the FERC regarding avoided cost pricing for QFs on October 21, 2010 in *California Public Utilities Commission* (2010) 133 FERC ¶61,059 (*FERC Clarification Order*).

We recently addressed the *FERC Clarification Order* and avoided cost under federal law in D.11-04-033.[22] We find the following excerpt from D.11-04-033, citing to the *FERC Clarification Order*, particularly instructive today as we adopt a new pricing methodology for the FiT Program:

> In this order [*FERC Clarification Order*], FERC clarified that the state has a wide degree of latitude in setting avoided cost, can utilize a multi-tiered avoided cost rate structure, and that this approach is consistent with the avoided cost requirements set forth in Section 210 of PURPA. (*Id.* at pp. 24 & 30.) FERC also clarified that state procurement obligations can be considered when calculating avoided cost, and it specifically overruled its prior holding from *SoCal Edison* to the extent its current determination was inconsistent

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[20] California Public Utilities Commission, 132 FERC ¶ 61,047 (2010) ¶ 71; (FERC has stated that non-jurisdictional public entity sellers are not subject to restrictions imposed under PURPA, although they may voluntarily choose to become QFs.)

[21] Whether QF certification is required for generators participating in the § 399.20 FiT program is discussed separately, herein.

[22] D.11-04-033 (*Order Granting Limited Rehearing of Decision 10-12-055 on the Issue of GHG Compliance Costs, Modifying Decision, Denying Rehearing of Decision, as Modified, and Denying Motion to Stay*) at 7. This decision is the final decision implementing the Combined Heat and Power FiT as authorized by AB 1613.

> with that clarification. (*Id.* at pp 29-30 *referring to SoCal Edison* (1995) 71 FERC ¶ 61,269 at 62,080.)[23]

As we found in D.11-04-033, 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."[24] 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 account obligations imposed by the state that, for example, utilities purchase energy from particular sources of energy or for a long duration.[25]

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. These clarifications expand the pricing options the Commission can consider when determining the § 399.20 FiT Program price.

### 3.2. State Law – the Commission's Fundamental Responsibility and § 399.20

Under §§ 701, 728, and 761, the Commission's fundamental responsibility is to oversee the utility's provision of an adequate supply of safe and reliable

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[23] D.11-04-033 at 7.

[24] *Id*. at 11, *citing to FERC Clarification Order* at 26.

[25] *FERC Clarification Order* at 26.

electricity at just and reasonable rates. Today, in implementing the statutory amendments to § 399.20, we are guided by, among other things, the Commission's fundamental responsibility and the rules of statutory construction, as discussed below.

#### 3.2.1. Rules of Statutory Construction

In comments in response to the June 27, 2011 ALJ ruling, the Center for Energy Efficiency and Renewable Technologies (CEERT) pointed to the need for the Commission to follow the rules of statutory construction and to take into consideration the legislative intent incorporated into § 399.20. We consider these sources and give each the appropriate weight in implementing the statutory amendments to § 399.20.

We give primary weight to the rules of statutory construction as the primary task of this decision is to implement new statutory provisions. The California Supreme Court has enunciated clear standards for courts or state agencies construing a statute. The Commission must act as follows:

> . . . look to the statute's words and give them their usual and ordinary meaning. The statute's plain meaning controls the court's interpretation unless its words are ambiguous. If the statutory language permits more than one reasonable interpretation, courts may consider other aids, such as the statute's purpose, legislative history, and public policy. . . .
>
> Where more than one statutory construction is arguably possible, our policy has long been to favor the construction that leads to the more reasonable result. This policy derives largely from the

> presumption that the Legislature intends reasonable results consistent with the apparent purpose of the legislation.[26]

Although the courts remain the ultimate arbiters of statutory meaning, courts accord deference to the Commission's reasonable interpretation of statutes.[27] We apply these rules of statutory construction below as we interpret and implement the provisions, as amended, of § 399.20.

As noted in the above quoted excerpt, we are also guided by legislative findings, including, for example, Historical and Statutory Notes. CEERT's comments emphasize the importance of legislative history when implementing SB 32 and SB 2 1X. However, the rules of statutory construction, as set forth above, direct us to look first to the language of the statute itself and we give those words their usual and ordinary meaning. "If there is no ambiguity in the language of the statute, 'then the legislature is presumed to have meant what it said, and the plain meaning of the language governs.'"[28]

In this manner, today's decision applies the rules of statutory construction in implementing SB 380, SB 32, and SB 2 1X.

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[26] *Imperial Merchant Services, Inc. v. Hunt* (2009) 47 Cal.4th 381, 387-388; s*ee also, e.g., People v. Canty* (2004) 32 Cal.4th 1266, 1276 and *Lungren v. Deukmejian* (1988) 45 Cal.3d 727, 735.

[27] *Greyhound Lines, Inc. v. Public Utilities Commission* (1968) 68 Cal.2d 406, 410; *Lockyer v. City and County of San Francisco* (2004) 33 Cal.4th 1055, 1090-1091.

[28] *Smith v. Rae-Venter Law Group* (2002) 29 Cal.$4^{th}$ 345, 358.

#### 3.2.2. Senate Bill 2 1X and Feed-In Tariff Pricing Considerations

Most significantly for purposes of the § 399.20 FiT Program, SB 32 and SB 2 1X provided new direction to the Commission on how to determine the market price for the § 399.20 FiT Program.

SB 2 1X amended § 399.20(d), the statutory provision which sets the program's price, by removing the cross reference to now repealed § 399.15. Under the previously existing cross reference to § 399.15, D.07-07-027 established that the price for electricity purchased under § 399.20 was necessarily tied to the MPR, which was used to set a cost limitation on the RPS Program. [29] Specifically, in D.07-07-027 the Commission found that the pricing for electric generation under § 399.20 was the MPR,[30] adjusted for time-of-delivery factors.[31] Since the cross-reference to § 399.15 has been removed pursuant to SB 2 1X, electricity purchased under § 399.20 is no longer required to be tied to the MPR as it was

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[29] Under SB 1078, the MPR was initially established to provide an RPS contract price reasonableness benchmark and to serve a role in the cost containment mechanism. SB 1036 (Perata) modified the use of the MPR to be only part of the cost-containment mechanism by establishing a limited above-MPR fund for contracts whose price exceeded the MPR.

[30] The Commission previously defined "market price" in D.03-06-071 and D.04-06-015 to be the MPR. More information on the MPR can be found at http://www.cpuc.ca.gov/PUC/energy/Renewables/mpr.

[31] D.07-07-027 at 23-24. Regarding time-of-delivery factors, each utility determines these factors based on its analysis of the forward value of energy and capacity during different times of day and times of the year. This results, in practice, in each utility valuing electricity at different hours differently. As relevant to the MPR calculation under existing tariffs, the three large utilities use between six and nine time-of-delivery periods.

calculated for purposes of the larger RPS Program. Thus, the potential range of pricing outcomes for the § 399.20 FiT Program has expanded.

The SB 2 1X amendment to the pricing provisions provides, in pertinent part:[32]

> (d)(1) The tariff shall provide for payment for every kilowatt hour 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 ~~Section 399.15~~ *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 kilowatt hour 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.*

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[32] New statutory language is identified with italics and the deleted language is identified in strikeout.

For these reasons, under the recent statutory amendments, we can review the pricing options for renewable distributed generation for the § 399.20 FiT Program under a much broader framework.

In the most basic terms, SB 2 1X directs the Commission to consider the following when adopting a pricing methodology:

(1) Market price determined by the Commission (§ 399.20(d)(1));

(2) Long-term market price for fixed price contracts pursuant to an electrical corporation's general procurement activities (§ 399.20(d)(2)(A));

(3) Long term ownership, operating and fixed-price fuel costs (§ 399.20(d)(2)(B));

(4) Value of electricity products, e.g., base load, peaking, and as-available (§ 399.20(d)(2)(C));

(5) Kilowatt hour price (§ 399.20(d)(1));

(6) 10, 15, or 20 year contract terms (§ 399.20(d)(1));

(7) 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 (§ 399.20(d)(1));

(8) and two optional inputs, as follows:

- time-of-delivery (§ 399.20(d)(3)); and
- 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. (§ 399.20(e)).

Our analysis of the pricing proposals must include other provisions of § 399.20, which, while not directly addressing price, impact the structure of the program. These provisions of the statute include, for example, the requirement that generators be "strategically located," that the tariff be offered on a "first-come-first-served basis," and that "ratepayers that do not receive service pursuant to the tariff are indifferent to whether a ratepayer with an electrical generation facility receives service pursuant to the tariff."

### 3.3. Policy Guidelines

This decision establishes five core policy guidelines which underlie our adoption of a revised § 399.20 FiT Program price and other program elements. These core policy guidelines were initially set forth as a proposal in the June 27, 2011 ALJ ruling and in the Renewable FiT Staff Proposal.[33] Today, we rely on these guidelines for program implementation and analysis of the various pricing and program design proposals.

Similar to the Renewable Auction Mechanism (RAM) Program, set forth in D.10-12-048, we seek to create a market for small renewable distributed generation that harnesses renewable market forces to set a program price that minimizes costs to ratepayers, prevents overpayment, and stimulates market demand. We also seek to maximize contract value to the ratepayer and utility by using the market to determine the price and to prevent speculative projects from occupying limited program capacity. Also similar to the RAM Program, we seek to create a straightforward program that is easy to administer. Lastly, we seek to limit project development to areas within the existing infrastructure on the distribution system and avoid costly, lengthy, and controversial transmission

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[33] The foundation of these policy guidelines is found in SB 32, Section 1 (a)-(g), (Legislative Intent).

system network upgrades. In summary, these five policy guidelines are as follows:

1. Establish a feed-in tariff price based on quantifiable ratepayer avoided costs that will stimulate market demand;
2. Contain costs and ensure maximum value to the ratepayer and the utility;
3. Ensure administrative ease and lower transaction costs for the buyer, seller, and regulator;
4. Use existing transmission and distribution infrastructure efficiently; and
5. Establish project viability criteria to increase probability of successful projects within the program.

Parties commented upon the proposed policy guidelines set forth in the June 27, 2011 ALJ ruling and the Renewable FiT Staff Proposal and, generally, found these guidelines reasonable. Some parties provided additional input or expressed disapproval. Overall, we find that these guidelines provide an important secondary source of guidance as we implement SB 320, SB 32, and SB 2 1X. Our primary source of guidance, as stated above, is derived from the rules of statutory construction.

For these reasons, below we analyze the various pricing and program design proposals under federal law (avoided costs), state law (statutory interpretation of § 399.20), and these policy guidelines.

## 4. Price Recommendations by Parties and Staff

In the March 2011 briefs filed in R.08-08-009, July and August 2011 comments, and November 2011 comments on the Renewable FiT Staff Proposal, parties provided proposals for a pricing methodology under § 399.20. Generally, these proposals can be described as being based on the following price characteristics: (1) the MPR without adders, (2) the MPR with various adders,

(3) costs of specific technologies, (4) a net energy metering surplus compensation methodology, (5) California Independent System Operator (CAISO) Gen Hub plus a renewable energy credit (REC) value and adjustment, (6) RAM contracts with a locational adder plus adjustments, and (7) other options. In the discussion that follows, we summarize the proposals.

### 4.1. Market Price Referent Without Adders

PG&E, SDG&E, The Utility Reform Network (TURN), and California Utility Employees (CUE) support a price based on the MPR, adjusted based on time-of delivery factors, as permitted by the language in § 399.20(d)(2). These parties do not support any adders to the MPR.

While PG&E and SDG&E support reliance on the MPR, they also continue to question the legality of the Commission's adoption of the MPR for the FiT Program under federal avoided cost law and PURPA. They, therefore, support the utilities' voluntary reliance on the MPR, as updated for 2011 in Resolution E-4442. Voluntary reliance is preferred by the utilities because, according to the utilities, mandatory provisions of wholesale service can only be required by the Commission when the Commission authorizes the utilities to offer such mandatory wholesale service at avoided cost, as defined under federal law. Because the utilities do not view the Commission's MPR as an avoided cost for renewables under federal law, the utilities suggest that, if the Commission only allows utilities to voluntarily offer the § 399.20 FiT Program price at the MPR, legal disputes initiated by the utilities could be potentially avoided.

In further support of the continued reliance on the MPR, PG&E, SDG&E, TURN, and CUE point to the following: (1) continued reliance on the MPR is transparent since the MPR calculation has been repeatedly vetted, and (2) the

MPR is a familiar standard within the industry and, accordingly, continued reliance on the MPR will promote administrative ease and market stability.

### 4.2. Market Price Referent with Solar Photovoltaic Adder

California Solar Energy Industries Association (CALSEIA) supports reliance on the MPR adjusted for time-of-delivery factors and a "solar PV" adder. CALSEIA suggests that solar photovoltaic (PV) systems provide significant value to ratepayers above and beyond the threshold costs of the natural gas-fired proxy plant quantified in the MPR. According to CALSEIA, these additional value components include avoided transmission and distribution costs, the value of increased reliability, blackout avoidance and power quality, avoided air emission associated with natural gas combustion and the associated general societal health benefits.

### 4.3. Market Price Referent with Forest Biomass Adder

Placer County Air Pollution Control District (Placer County) supports using the MPR adjusted for time-of-delivery factors plus an adder for small forest biomass generation projects on the basis that small forest biomass projects sited in medium and high-risk fire hazard areas could provide significant value by (1) mitigating fire suppression costs; (2) reducing fire settlement awards; (3) reducing health costs from forest fire emissions; (4) protecting utility transmission and distribution assets from fire damage; and (5) protecting the water supply and personal property from fire-related damages.

Placer County's specific proposal consists of a $0.055 per kWh "Wildfire Hazard Reduction Adder" and a 50 MW carve-out for small forest biomass. The adder includes the five-year average (2006-2010) annual cumulative cost to the California Department of Forestry and Fire Protection, the U.S. Forest Service, and the U.S. Bureau of Land Management for statewide wildfire suppression of $1.201 billion. Placer County states that not all the adder costs are paid by ratepayers of the utilities but instead are paid by federal and state taxpayers generally, which consists of a larger segment of the population than the utilities' ratepayers. Placer County calculates the ratepayer share of the total taxpayer amount is $900,782,000.

Placer County's analysis also relies on a recent study by the U.S. Forest Service and sponsored by the California Energy Commission (CEC),[34] finding that strategic placement of small forest biomass facilities across Northern California could reduce the number of acres burned by wildfire in California by 23.5% per decade, or approximately 2.3% annually.

### 4.4. Market Price Referent with Environmental and Locational Adders

Silverado Power LLC (Silverado Power), the Solar Alliance, and Vote Solar Initiative generally support using the MPR, adjusted for time-of-delivery factors, as the base price but also suggest a locational adder based on avoided costs for distribution losses, transmission losses, congestion, and transmission and distribution investments. They suggest that § 399.20(d)(1) ("the payment …shall include current and anticipated environmental compliance costs for facilities in local air pollution control or management districts") could require an

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[34] USDA Forest Service, Pacific Southwest Research Station. 2009. *Biomass to Energy: Forest Management for Wildfire Reduction, Energy Production, and Other Benefits.* California Energy Commission, Public Interest Energy Research (PIER) Program, CEC-500-2009-080.

environmental pricing component but state that no further environmental adjustments are warranted because the MPR already includes an environmental component. In response to this proposal, TURN points out that the Commission modified the 2009 MPR model to include an escalating annual cost of carbon dioxide ($CO_2$) and other environmental inputs that capture costs related to nitrogen oxides ($NO_x$), sulfur oxides ($SO_x$), particulate matter ($PM_{10}$), and volatile organic compounds (VOC).[35]

Clean Coalition also supports continued reliance on the MPR adjusted to reflect time-of-delivery payments per § 399.20(d)(3), all current and anticipated environmental compliance costs per § 399.20(d)(1), and locational benefits per § 399.20(e). Regarding environmental benefits, Clean Coalition acknowledges that the MPR currently captures some environmental costs but suggests that under § 399.20(d)(1) the Commission has authority to make further adjustments. Specifically, Clean Coalition recommends that the MPR be adjusted to capture current or future additional environmental compliance costs, including those costs noted by a report cited in CALSEIA's comments[36] on the value to ratepayers of avoided methane, $NO_x$, $CO_2$, $SO_x$, VOCs, and $PM_{10}$ emissions. Clean Coalition suggests this value could be represented by the addition of 1 cent/kWh to the MPR. Regarding locational benefits, Clean Coalition suggests this value could be represented by the addition of 35% of the MPR based on the

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[35] *See* Resolution E-4298 (issued December 18, 2009). This resolution formally adopted the 2009 MPR values for use in the 2009 RPS solicitations.

[36] http://calseia.org/wp-content/uploads/2010/05/pv-above-mpr-methodology-final-20100423.pdf.

type of grid support provided, such as avoided transmission, avoided line losses, reliability and blackout prevention, and improved power quality.

### 4.5. Technology-Specific Pricing

In the March 2011 briefs and comments filed in July, August, and November 2011, parties, including CEERT, Agricultural Energy Consumers Association and the Inland Empire Utilities Agency, California Wastewater Climate Change Group (CWCCG), Sustainable Conservation, Green Power Institute (GPI), FuelCell Energy, Renewables 100, Sierra Club California (Sierra Club), and Solar Alliance, recommend unique prices for different types of renewable resources.

CEERT supports a § 399.20 FiT Program price that reflects the resource and technology used to generate electricity, as well as the locational attributes of the generation site.[37] CEERT finds that, under existing federal and state law, it is possible for each generation project under the § 399.20 FiT Program to be given a different market price of electricity because according to CEERT, avoided cost can be defined under the law as specific to each resource, technology, and location. CEERT does not, however, recommend that pricing be developed for each individual project. Rather, CEERT recommends that the market price of electricity under § 399.20(d)(1) be differentiated according to resource types, with an avoided cost price determination that reflects the cost of the resource, including the environmental, locational, and supply characteristics of each resource. In this manner, CEERT suggests that the applicable avoided cost price

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[37] CEERT July 21, 2011 comments at 2.

can be tailored to the market segment targeted in § 399.20, which includes projects uniquely situated closer to load centers and sized to interconnect at the distribution level. CEERT claims this approach is appropriate because such projects have not been effectively incorporated into any other RPS procurement mechanism.

Sustainable Conservation and GPI also suggest that the Commission adopt technology-specific pricing based on the costs of each technology. According to Sustainable Conservation and GPI, the "market price of electricity" in § 399.20 is an imprecise term and the Commission has significant latitude to set tariff prices. Sustainable Conservation and GPI further suggest that their cost-based pricing proposal be differentiated based on more than just the three electricity product types (baseload, peaking, and as-available) listed in the statute because some generators provide services to the utilities beyond those three types. For example, these parties point out that lagoon systems for dairy farms can be equipped with gas storage at low cost, which allows operations that are not just simple baseload, as is typical for biogas generators, but baseload with the capability of providing load-following services if the appropriate incentives are included in the contract. For these reasons, Sustainable Conservation and GPI support cost-based pricing as a means to diversify California's renewable energy portfolio to include a greater share of biomass, biogas, and other gasification technologies.

While supporting cost-based pricing, Sustainable Conservation and GPI also recognize that data on the costs of these resources is minimal because these industries are largely in the early commercialization phase. To support their position, they suggest two sources of publicly available price data: (1) a CEC-funded study[38] and (2) a State Water Resources Control Board study.[39]

CWCCG suggests that technology-specific pricing is critical to appropriately provide an incentive for renewable generation at water and wastewater facilities. CWCCG claims that many wastewater agencies already generate some or all of their electrical power, much of this using biogas, but without a technology specific cost-based price that is higher than the current and past MPRs, water and wastewater facilities lack a financial incentive to sell electricity to the utilities.

FuelCell Energy acknowledges that, under the existing legal framework, "there is more than one way the Commission can calculate a price"[40] for the § 399.20 FiT Program. FuelCell Energy supports technology-specific pricing that reflects the value of stationary fuel cells using renewable fuels. FuelCell Energy points to several sources of data for the Commission to calculate a technology-specific price for stationary fuel cells: a study by the University of California and the record of the Commission's proceeding in Application

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[38] Cheremisinoff, Nicholas, Kathryn George, and Joseph Cohen, 2009. *Economic Study of Bioenergy Production From Digesters at California Dairies.* California Energy Commission, PIER Program. CEC-500-2009-058.

[39] California Regional Water Quality Control Board, Central Valley Region, *Economic Feasibility Of Dairy Manure Digester And Co-Digester Facilities In The Central Valley Of California, May 2011*.

[40] FuelCell Energy March 7, 2011 brief at 15.

(A.) 09-02-013 and A.09-04-018.[41] FuelCell Energy explains that this data quantifies the incremental value of fuel cell-specific attributes over and above the MPR. These values include avoided capital, operation and maintenance, fuel costs, water use, transmission and distribution, inputs for use of digester gas, cogeneration applications, and general societal benefits provided by fuel cells, including job creation and ease and speed of deployment.

### 4.6. Net Surplus Compensation Rate

The Division of Ratepayer Advocates (DRA) suggests that the pricing for the § 399.20 FiT Program be derived from the net energy metering net surplus compensation rate. DRA points out that the net surplus compensation rate is an established tariff based on market prices adjusted for renewable attributes. The Commission adopted the net surplus compensation rate in D.11-06-016 to apply to the excess generation from net-energy metered customers. Specifically, the net surplus compensation rate is derived from an hourly day-ahead electricity market price known as the "default load aggregation point" (DLAP) price. In 2009, this average DLAP price for PG&E was approximately four cents per kWh. Net surplus generators may also be compensated at the net surplus compensation rate plus an adder for their renewable attributes based on an interim proxy rate derived from the Western Electricity Coordinating Council average renewable energy premium, published by the Department of Energy. DRA suggests that such a rate could provide price stability to future FiT

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41 FuelCell Energy cites to a 2008 study issued by the National Fuel Cell Research Center at the University of California-Irvine, *Build-Up of Distributed Fuel Cell Value In California: Background and Methodology*.

participants and creates transparency because the price is based on publicly available information.

### 4.7. CAISO Gen Hub plus REC Pricing with Adjustment Mechanism

SCE supports a market-based pricing approach on the basis that it would enable the Commission to price the program outside of the restrictions imposed by PURPA and avoided cost limitations. SCE claims that its market-based proposal has many benefits. According to SCE, its proposal avoids the need for a time-consuming and contentious examination of avoided cost. In addition to a Gen Hub base price, it also includes a market-based pricing adjustment mechanism where the price adjusts based on market response. Thus, unlike the administratively-determined prices, such as the MPR, the price will not remain static, at a point potentially too high or too low. Instead, the price could move higher or lower in response to supply and demand of renewable energy in the market. According to SCE, in contrast to a static price, this more flexible proposal offers potential benefits to ratepayers because ratepayers will not have to pay excessive costs for renewable energy if the market price drops. Similarly, sellers would potentially benefit by being able to accept a contract at a price sufficient to develop their projects.

As set forth in its August and November 2011 comments, the main points of SCE's proposal are as follows:

(1) SCE would publish an initial FiT price the first day of each month;

(2) The initial FiT price would be based on an average of the historical one-year day-ahead South Path-15 EZ Gen Hub price published by the CAISO plus the Department of Energy established price for renewable attributes in the Western United States;

(3) A portion of the overall program capacity will be allocated for procurement each month.

(4) The FiT price would increase at an escalating rate each consecutive month in which there is no program subscription (e.g., $2/MWh, then $4/MWh, then $6/MWh, etc.)[42]

(5) The FiT price would decrease at an escalating rate each consecutive month in which there is full subscription (e.g., $2/MWh, then $4/MWh, then $6/MWh, etc.)

(6) If there is partial subscription in any given month, the FiT price would stay the same for the next month.

(7) Any program capacity not subscribed in a month would roll over into the next month.

### 4.8. RAM Pricing with Locational Adder and Adjustment Mechanism

In their July and August comments, Interstate Renewable Energy Council (IREC), Silverado Power, Vote Solar Initiative, and SunEdison LLC (SunEdison) suggest the Commission set a revised FiT price based on the results of the RAM auction adjusted for time-of-delivery factors. In the Renewable FiT Staff Proposal, the Commission's Staff endorsed this proposal and offered expanded details on how to implement it. The following pricing methodology was presented by Staff:

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[42] SCE changed this aspect of its proposal in its November 2011 comments from its initial presentation in its August 2011 comments.

**Base Price Calculation**:

(1) Use the results of the RAM auction (with the first RAM auction closing November 15, 2011) to set the price for the § 399.20 FiT Program. At the time the Commission's Staff issued its proposal, the first RAM auction had not yet closed. The first auction has since closed. The individual bid prices are confidential.

(2) Set a price for three product types: baseload, peaking as-available, non-peaking as-available.

(3) Use the RAM market clearing price from each product type, which will be the highest RAM executed contract price.

(4) Add to the price the project's share of the transmission costs for the particular RAM contract. If the generator triggers transmission costs, then the generator should not receive any payment for avoided transmission.

(5) Adjust price for time-of-delivery factors to capture the value of the product to ratepayers.

**Price Adder and Adjustments:**

The Renewable FiT Staff Proposal also recommends a locational adder for generation located in so-called "hot spots." Hot spots are defined in the Staff Proposal as "areas where distribution and transmission system upgrades can be deferred if new generation is located in that area."[43] Lastly, the Staff Proposal recommends a price adjustment mechanism for each product type for each utility after a certain subscription level (or lack thereof). Staff did not recommend a particular adjustment mechanism but rather referred to CALSEIA, SCE, Clean Coalition, and Vote Solar Initiative's recommendations.

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[43] Renewable FiT Staff Proposal at 7 (attached to ALJ Ruling dated October 13, 2011).

## 5. Analysis of Party and Staff Price Recommendations

### 5.1. Market Price Referent without Adders

PG&E, SDG&E, TURN, and CUE support establishing a market price using the MPR adjusted for time-of-delivery factors. This has been the § 399.20 FiT Program's pricing methodology since the program's inception in 2007. A pricing methodology based on the MPR is an established tested methodology and would be familiar to the renewable energy industry. An MPR-based methodology would offer a high degree of transparency since market participants are well acquainted with the costs embedded within the MPR, such as certain environmental costs. DRA, however, finds the MPR sets an "unrealistically low/unachievable price point" for certain technologies and will fail to support the success of the § 399.20 FiT Program.

We agree with DRA in part. The MPR price may be too high or too low for different FiT product types. We also find using the MPR to set § 399.20 FiT Program price fails to achieve our first policy guideline: to "establish a feed-in tariff price based on quantifiable utility avoided costs that will stimulate market demand." The MPR is a price based on a natural gas-fired electric plant, and not a renewable generator. Specifically, the MPR does not reflect ongoing changes within the renewable market and, as a result, could potentially result in a price either too low or too high. In addition, the renewable market has evolved since the Commission first established the MPR in 2003 at the beginning of the RPS program. Now the renewable market is sufficiently robust to serve as the point of reference for establishing the market price for small renewable projects rather than the very different benchmark used for the MPR, which is based on the costs of a combined-cycle natural-gas power plant.

Therefore, because the renewable market is sufficiently robust to serve as a point of reference for the market price for the § 399.20 FiT Program price, we decline to adopt a pricing proposal that relies upon the MPR.

### 5.2. Market Price Referent with Various Adders

As discussed above, CALSEIA, Placer County, Silverado Power, the Solar Alliance, Vote Solar Initiative, Clean Coalition, and other parties support a pricing proposal based on adjusting the MPR with some type of adder, for example, an adder based on the attributes of a specific technology type, locational conditions, or environmental societal benefits. In the above discussion, we decline to adopt a pricing proposal based on the MPR because, in short, the renewable market is sufficiently robust to more accurately reflect generation costs of the FiT Program as compared to the cost reflected in the MPR, that of a natural gas plant. For this same reason, we decline to adopt the MPR aspect of these proposals.

Regarding the adders recommended by the above parties, we decline to adopt the following adders: solar adder, small forest biomass adder, and environmental adders. We decline to adopt these adders because we do not adopt the MPR as the basis for the § 399.20 FiT Program's price and, as described in more detail at Section 6, below, the basis for the pricing adopted today is the renewable market, which already reflects a value for these adders. In addition, the methodologies used for these adders were generally based on avoided societal costs, and not avoided utility costs, and are therefore not the type of avoided costs permitted under PURPA.

In addition, these adders were proposed in order to increase the FiT price above the MPR for technologies that may need higher prices. Given the price adjustment mechanism that is adopted in this decision, adders are not necessary.

The FiT price should adjust to account for the market price of various resources. If we find that the adjustment mechanism does not reflect the market, including certain market segments that have additional ratepayer value, the Commission can consider adders in the future.

Furthermore, these adders are inconsistent with three of the policy guidelines: (1) establish a feed-in tariff price based on quantifiable utility avoided costs that will stimulate market demand; (2) contain costs and ensure maximum value to the ratepayer and utility; and (3) ensure administrative ease and lower transaction costs for the buyer, seller, and regulator. As stated above, many of the proposed adders are overly broad societal costs and not based on the avoided costs to utilities. In addition, these adders could increase the contract price above the market price of generation from eligible renewable energy resources and lead to overpayment. As discussed below, the FiT price calibrates to market prices and to market demand, which leads both to reasonable ratepayer costs and prices that can work to stimulate market demand. Last, calculating adders for each technology or specific resource attribute increases the administrative complexity for the program and increases the burden on Commission's Staff to administer the program. For these reasons and the reasons articulated above, we do not adopt the requested adders for the § 399.20 FiT Program.

### 5.3. Technology-Specific Pricing

The parties advocating technology-specific pricing articulate a key challenge in implementing the § 399.20 FiT Program: establishing an avoided cost pricing methodology consistent with the provisions of state law and federal law that supports specific types of renewable technologies, which provide general societal benefits that cannot easily be quantified. We seek to create a pricing policy that supports a diversity of technologies. In doing so, we must balance a number of competing interests, and find that, at this time, unique prices for separate technologies are not required by state law or in the best interest to ratepayers.

Regarding the state law issue, the parties do not address the fact that § 399.20 does not specifically direct the Commission to account for the unique cost of each technology. The plain language of § 399.20 does not require that technology-specific costs be included in a FiT Program price methodology.

Parties refer to § 399.20(d)(1)[44] to support their position on consideration of technology classifications. This subsection is addressed in a separate section in this decision.

Some parties suggested that federal law supports technology-specific prices. While federal law, as discussed above, provides the Commission with the latitude to take into account state energy procurement requirements when establishing avoided costs, the state statute, as codified in § 399.20, does not require the Commission to consider technology-specific costs when determining the § 399.20 FiT Program price.

We also find technology-specific pricing inconsistent with three of our policy guidelines: (1) Establish a feed-in tariff price based on quantifiable utility

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[44] This statute refers to certain costs that the Commission must consider in setting a tariff price and provides, in pertinent part, as follows: "The payment…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."

avoided costs that will stimulate market demand; (2) Contain costs and ensure maximum value to the ratepayer and utility; and (3) Ensure administrative ease and lower transaction costs for the buyer, seller, and regulator.

Technology-specific pricing does not establish a § 399.20 FiT Program price based on the renewable market and competitive pressures but rather would use administratively-determined calculations to establish a price based on the costs plus a fair rate of return to build and operate a specific technology. Ultimately, we find this method of calculating price will weaken the ability for competition to control contract costs.

Next, this method does not ensure the maximum value to the ratepayer and utility. For example, if different technologies within a product type have the same value to the utility but different costs, the utility is going to overpay since the more expensive technologies have the same value as lower priced technologies.

Finally, determining the costs of each renewable technology increases the administrative complexity and the transaction costs for the regulator, who is responsible for calculating each technology's cost for the § 399.20 FiT Program.

Accordingly, we do not adopt technology-specific pricing as it is not required by § 399.20 and does not advance our policy guidelines for implementing the § 399.20 FiT Program. We do, however, seek to encourage a diversity of technologies through our adopted pricing methodology.

### 5.4. Net Surplus Compensation Rate

AB 920 amended § 2827 in order to pay net-energy metered customers for their excess generation over a one-year period. D.11-06-016 found that net surplus generation by net-energy metered customers has no capacity value because an individual net-energy metered customer has no obligation to provide energy to the utility. Net surplus generation is provided without a power purchase agreement on an intermittent, unpredictable, and as-available basis over a 12-month period. In addition, the Commission found that the only generation the utility avoids when a net-energy metered customer provides surplus generation is reduced electricity procurement from the short-term wholesale market.

Since renewable generators under the § 399.20 FiT Program are required to sign long-term power purchase agreements (a minimum of 10 years per § 399.20), generators under the § 399.20 FiT Program represent a different value than the net surplus compensation from net-energy metered customers and, accordingly, should not be paid the same rate. Finally, we find that the net surplus compensation rate violates our first policy guideline, to "establish a feed-in tariff price based on quantifiable utility avoided costs that stimulate market demand," since the rate is based on the hourly day-ahead electricity market price, or DLAP price, and not the market price for renewable electricity.

Accordingly, because the market served by net-energy metered customer is different than the market served by the § 399.20 FiT Program, we do not adopt a pricing methodology based on the net-surplus compensation rate.

### 5.5. CAISO Gen Hub plus REC with Adjustment Mechanism

We decline to adopt SCE's proposal to use the CAISO Gen Hub plus the REC as the § 399.20 FiT Program starting price for the same reasons we do not adopt the net surplus compensation rate. We find merit, however, in SCE's recommendation to rely on the market to set a starting price for the FiT Program and agree that a price set by the market avoids the need for a time-consuming and contentious examination of costs. A market-set price permits flexibility and responds to market demand. We also find merit in SCE's recommendation to adjust the § 399.20 FiT Program starting price based on market conditions since this mechanism will allow the starting price to adjust to renewable market prices if it is initially set too high or too low. Therefore, we adopt SCE's adjustment mechanism, in part, as articulated in its August and November 2011 comments.

### 5.6. RAM Pricing with Locational Adder and Adjustment Mechanism

As more fully discussed in Section 6, below, we adopt the component of the proposals by IREC, Silverado Power, Vote Solar Initiative, SunEdison, and Staff that relies on RAM contracts adjusted for time-of-delivery factors to set the § 399.20 FiT Program starting price. When combined with SCE's adjustment mechanism, using RAM contracts to set the FiT Program starting price is consistent with the three policy guidelines that relate to choosing a FiT price: (1) establish a feed-in tariff price based on quantifiable utility avoided costs that stimulate market demand; (2) contain costs and ensure maximum value to the ratepayer and utility; and (3) ensure administrative ease and lower transaction costs for the buyer, seller, and regulator. Section 6, below, more fully describes the adopted market-based pricing methodology, which is referred to as the Renewable Market Adjusting Tariff (Re-MAT), and includes an analysis of the adopted market-based pricing methodology under federal and state law.

We do not adopt other components of the Renewable FiT Staff Proposal, including the location adder or a transmission adder because we find these components, as proposed during the proceeding, to be inconsistent with existing law . Any location or transmission adder must be based on costs that are found to be actually avoided by the utilities. (18 C.F.R. § 292.304, subd. (a)(2); *FERC Clarification Order, supra,* 133 FERC ¶ 61,059, at P 31.) In this case, we agree with the concerns expressed by SCE and the other utilities, and find that the record does not support a finding that the location and transmission adders proposed during the proceeding represent actual costs that would be avoided by the utilities. (See, e.g., *Southern California Edison Company's Reply Comments on the October 13, 2011 Renewable FIT Staff Proposal*, dated November 14, 2011, pp. 12-13; *Pacific Gas and Electric Company's Comments on Staff Proposal Regarding the Implementation of Section 399.20*, dated November 2, 2011, pp. 17-19.) Furthermore, the requirement that projects in the § 399.20 FiT Program be "strategically located," as discussed separately in Section 6.9, addresses the concerns that parties and Staff sought to address through a locational adder, which is to provide an incentive to generators to locate in areas with load in order to avoid upgrades to the transmission system.

## 6. Adopted FiT Pricing Methodology – Renewable Market Adjusting Tariff or Re-MAT

Section § 399.20 contains a number of mandatory and discretionary considerations that apply to any pricing methodology adopted by the Commission for the FiT Program. The pricing methodology must also be consistent with federal law on avoided costs for wholesale transactions under PURPA. Today's decision adopts a pricing methodology that relies upon renewable market power pricing information from the RAM adopted in D.10-12-048 and takes components from a number of different pricing proposals presented by parties, including IREC, SunEdison, Silverado Power, Vote Solar Initiative, SCE and Staff. Importantly, we adopt an adjustment mechanism to increase or decrease the FiT price for a particular product type based on market conditions. The pricing methodology we adopt today, Re-MAT, complies with both state and federal law.

### 6.1. Compliance with Federal Law

In prior decisions, we found that the FiT price was constrained by the statutory cross-reference to § 399.15 within the FiT statute, § 399.20. We further found that, based on this cross-reference to § 399.15, pricing for FiT was limited to the MPR. Today, based on the removal of this cross-reference, we have greater latitude to consider other pricing options under state law.[45] As discussed above, FERC's recent interpretations in response to a petition for declaratory order also support consideration of additional pricing options, as long as the facilities are QFs and the pricing options are an avoided cost. Therefore, it is reasonable for us to shift the price away from the MPR to the renewable power market. We further find that a FiT price that reflects the renewable market ultimately more fully reflects avoided costs under federal law. Therefore, relying on the existing RAM Program to establish the baseline for pricing is a reasonable starting point to determine avoided cost for the § 399.20 FiT Program.

Because the § 399.20 FiT Program seeks to implement a directive from the Legislature to procure energy from specific sources, renewable generation of 3 MW and less, and to consider the value of different electricity products, including baseload, peaking, and as-available electricity, we find using RAM contracts to set the § 399.20 FiT Program starting price, which includes these product types, is the most reasonable alternative to determining the cost of the resources being avoided.

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[45] *See* Section 3.1, above, for a more detailed discussion of the changes to the statutory language in § 399.20 relevant to the cross-reference.

Our finding is based on the fact that the renewable market has evolved, and is now sufficiently robust to serve as the point of reference for the market price for small renewable projects. The discussion above at Section 5 fully addresses this matter.

The market segments covered by RAM and § 399.20, however, are not the same. RAM covers renewable projects sized up to 20 MW. The § 399.20 FiT Program covers renewable projects sized up to 3 MW. Other renewable procurement programs include the RPS Annual Solicitation and bilateral contracting process, which generally result in contracts greater than 20 MW and as large as 1,000 MW, with an average size of about 100 MW. We address the disparity between the RAM and the § 399.20 FiT Program markets by adopting a price adjustment mechanism, described further in Section 6.4, which will enable the FiT price to be responsive to market conditions. We find that the adopted Re-MAT, which uses the RAM as a starting price and employs a price adjustment mechanism, establishes a market-based avoided cost for the § 399.20 FiT Program.

### 6.2. Compliance with State Law

In terms of compliance with state law, we find that our proposal meets the requirements of § 399.20. The Legislature provided specific information that we must consider in setting the § 399.20 FiT Program price but left the Commission with the discretion on how to factor these considerations into any pricing methodology that we ultimately adopt.

Section 399.20(d)(1) provides that the tariff price shall be, among other things, the market price determined by the Commission. Today, the Commission adopts a market price by relying on contracts approved from a specific renewable auction market, specifically the RAM auction set forth in D.10-12-048.

In addition, the Re-MAT's adjustment mechanism seeks to account for any differences in pricing from the RAM Program and the § 399.20 FiT Program by increasing or decreasing the price if the initial price is too low or too high. The pricing methodology is also guided by other provisions of § 399.20 that are discussed elsewhere in this decision. These provisions include, for example, that the generation be "strategically located," that the tariff be offered on a "first-come-first-served basis," and that "ratepayers that do not receive service pursuant to the tariff are indifferent to whether a ratepayer with an electrical generation facility receives service pursuant to the tariff."

Specifically, the Re-MAT is in compliance with the following provisions of § 399.20:

Section 399.20(d)(2)(A) provides that the Commission shall establish a price in consideration of the long-term market price for fixed price contracts pursuant to an electrical corporation's general procurement activities. The Commission has considered the long-term market price for fixed price contracts pursuant to an electrical corporation's general procurement activities because today's adopted methodology, Re-MAT, relies upon RAM contracts as set forth in D.10-12-048, which are part of each electrical corporation's general procurement.

Section 399.20(d)(2)(B) provides that the Commission shall establish a price in consideration of long term ownership, operating and fixed-price fuel costs. The Commission has considered long term ownership, operating and fixed-price fuel costs because Re-MAT relies upon RAM contract prices as set forth in D.10-12-048 which includes such costs.

Section 399.20(d)(2)(C) provides that the Commission shall establish a price in consideration of the value of electricity products, e.g., baseload, peaking, and as-available. The Commission has considered the value of different electricity products because Re-MAT's adopted market-based methodology includes pricing for three product types.

Section 399.20(d)(1) provides that the tariff shall provide for payment of every kilowatt hour of electricity purchased. The Commission has adopted a mechanism that establishes a kWh price and, therefore, is in compliance with this provision.

Section 399.20(d)(1) provides that the tariff shall provide for payment for a period of 10, 15, or 20 years. The adopted price methodology permits contracts of any of these terms.

Section 399.20(d)(1) provides that the tariff shall provide for payment of, among other things, 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. Re-MAT theoretically includes, as embedded within the starting price, general costs associated with producing renewable energy. As the Re-MAT should calibrate to the market price of the renewable energy, we find that the Re-MAT price should account for all of a generator's costs, including the generator's environmental compliance costs.

A more specific discussion of the components of Re-MAT follows.

### 6.3. Three Product Types and Re-MAT Starting Price

The existing FiT Program based on the MPR does not distinguish among different product types and only offers one price. Section 399.20(d)(2)(C) directs the Commission to consider, and today's decision adopts, a price for each of the following three product types: baseload, peaking as-available, and non-peaking as-available. Our decision reflects an effort to better capture the value provided by different product types, which should accurately reflect the value of the different technologies that produce these products. Baseload projects provide firm energy deliveries (e.g., bioenergy and geothermal); peaking projects provide non-firm energy deliveries during peak hours (e.g., solar); and non-peaking as-available projects provide non-firm energy deliveries during non-peak hours (e.g., wind and hydro).

For each of the three FiT product types, we adopt a Re-MAT starting price for the § 399.20 FiT Program based on the weighted average of PG&E's, SCE's, and SDG&E's highest executed contract resulting from the RAM auction held in November 2011. While a unique starting price for each product type was considered as an option, we opted otherwise because the November 2011 RAM contract prices contained insufficient market information for the three product types to render this option viable.[46] As a result, we adopt PG&E's recommendation articulated in its November 2011 comments to use a weighted average of the highest executed RAM contract from each investor owned utility (IOU) to establish a single, statewide FiT starting price for each of the three product types. This is a reasonable starting price for the FiT because it is set by the most recent comparable competitive solicitation for renewable generation.

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[46] The utilities recently filed advice letters seeking Commission approval of the auction results from the first RAM solicitation, PG&E Advice Letter 4020-E (March 20, 2012), SCE Advice Letter 2712-E (March 29, 2012), SDG&E Advice Letter 2343-E (April 3, 2012).

In addition, we find it prudent to adjust this starting price by time-of-delivery factors based on the generator's actual energy delivery profile, since this captures the value of each generator to the utility. Lastly, we find that the price adjustment mechanism, described below, adequately functions to capture the different costs associated with the small renewable distributed generation market segment compared to the RAM market segment.

Based on the results from the November 2011 RAM auction, we anticipate that the starting price for each separate product type will be $89.23/MWh (pre-time-of-delivery adjustment). [47] PG&E, SCE, and SDG&E shall incorporate this starting price, the price adjustment mechanism, and incremental capacity releases, as discussed below, into their tariffs and standard contracts, as appropriate, for the § 399.20 FiT Program.

### 6.4. Re-MAT Price Adjustment Mechanism For Each Product Type

We also adopt a price adjustment mechanism for the three product types, i.e., baseload, peaking as-available, and non-peaking as-available. A proposal for triggering a price adjustment was included as part of SCE's August 5, 2011 comments,[48] and we adopt SCE's proposal, in part. Under the adopted price

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[47] SCE executed contracts from the first RAM auction on February 13, 2012. PG&E executed contracts from the first RAM auction on February 27, 2012. SDG&E executed contracts from the first RAM auction on March 30, 2012. The Commission's Energy Division Staff approved these contracts, effective April 29, 2012 for PG&E, April 30, 2012 for SCE, and May 3, 2012 for SDG&E.

[48] *Southern California Edison Company's Program Implementation Proposal Pursuant to Section 399.20 Ruling Dated June 27, 2011*, dated August 5, 2011, Appendix A Schedule

*Footnote continued on next page*

adjustment mechanism, the price for a utility's product type may increase or decrease every two months provided certain conditions exist. Each utility will make the FiT prices publicly available on its website by the first business day of the month in which the price adjustment occurs.

A price adjustment mechanism will enable the FiT price to quickly respond to market conditions. It is also designed to prevent gaming by only increasing or decreasing provided that a defined level of market interest exists for a product type. [49]

As part of today's decision, interested generators that meet the program's minimum project viability criteria (Section 10) must submit a program participation request form to the utility. Once the participation request form is deemed complete, the utility will establish a queue on a first-come-first-served basis for each product type. Every two months, the utility will offer generators a FiT contract at that two-month Re-MAT price in order of the Re-MAT queue. A generator can accept or reject the price. If a generator accepts the price, it enters into a FiT contract. The price is fixed for the term of contract. If the generator declines a contract at that price, it maintains its position in the queue until the next two-month period.

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MP FiT, Sheet 5, Special Condition #8 MP FiT Pricing and Cumulative Procurement Targets."

[49] For example, a price adjustment mechanism should not create an incentive for generators to purposefully withhold executing a contract in order to force a price increase.

The price adjustment will be triggered only after at least five eligible projects by different developers are in the queue. If there are less than five projects by different developers for any two-month offering, then the Re-MAT price remains the same for the next two-months. If at least five eligible projects by different developers are in the queue, the price may increase or decrease based on whether projects accept the Re-MAT price and a certain subscription level is met. If no developer enters into a FiT contract at the two-month price, then a price increase will be triggered for the following two-month period. Or, if the threshold of five eligible projects with different sponsors is achieved and the all available capacity is subscribed for in a product type, a price decrease is triggered for the following two-month period.

The manner in which the mechanism will function to increase or decrease the price is described below.

#### 6.4.1. Increased Price - Illustrated

As stated above, if there are five projects with different developers in the queue for a particular project type and if certain conditions exist, the Re-MAT price will adjust in the subsequent two-month period. The condition for a price increase is either (1) if no projects subscribe or (2) if program subscription for a two-month period is less than 50% of the initial starting capacity for that project type. There must also be at least five eligible projects from different sponsors in a utility's queue for a product type. The price will increase for each consecutive two-month period until there is subscription capacity equal to 50% or more of the initial starting capacity for that product type. At that point, the price remains the same until the criteria for a price decrease are met. The following serves to illustrate how this mechanism works to increase the price:

- Months 1-2: Starting Price ($89.23/MWh). If no subscriptions result or less than 50%, then the price increases as follows:
- Months 3-4: Starting Price + $4.00/MWh (total $4.00/MWh increase over prior period) and, if no subscription results or less than 50%, the price increases as follows:
- Months 5-6: Starting Price+ $12.00 (total of $8.00 increase over prior period) and, if no subscription results or less than 50%, the price increases as follows:
- Months 7-8: Starting Price + $24.00 (total of $12.00 increase over prior period) and, if no subscription results or less than 50%, the price increases as follows:
- Months 9-10: Starting Price + $40.00 (total of $16.00 increase over prior period) and, if no subscription results or less than 50%, the price increases as follows:
- Months 11-12: Starting Price + $60.00 (total of $20.00 increase over prior period).

Any program capacity not subscribed in a two-month period will be distributed as described in Section 6.5.

It is our expectation that more expensive technologies such as biogas and forest biomass, may gain the opportunity to participate in the FiT Program by, for example, Months 9-10, after the price has increased by $40/MWh to $129.23, assuming no subscriptions in the product type have occurred before that date and a minimum of five project sponsors exist in the Re-MAT queue. Additional time may be required to reach that price if less expensive technologies subscribe to the product type.

To guard against ratepayer exposure to excessive costs due to market manipulation or market malfunction, PG&E, SCE, and SDG&E shall file a motion to temporarily suspend all or part of the program when evidence of market manipulation exists. The motion will be acted upon expeditiously. The motion shall identify the portion of the program suspended, the specific behavior and reasons for the suspension, and the utility's proposal for resolving the program. The motion shall be served on the service list of this proceeding or any successor proceeding. The utilities must rely upon this motion in a manner that minimizes disruption of the program. For example, if a utility identifies market manipulation or malfunction in one product type or by one project sponsor, the motion requesting the suspension should be limited accordingly. In this manner, the suspension will balance the need to protect ratepayers from excessive costs without unreasonably hindering the functioning of the program.

#### 6.4.2. Decreased Price - Illustrated

As previously discussed, if there are five projects with different developers in the queue for a particular project type and if certain conditions exist, the Re-MAT price will adjust in the subsequent two-month period. The condition for a price decrease is if subscription in a two-month period equals 100% of the initial capacity allocation for that produce type, regardless of the total available capacity for that product type for the two-month period. The price will stay the same if subscription in the two-month period is less than 100% of the initial capacity allocation for that product type. The following serves to illustrate how this mechanism works to decrease the price:

- Months 1-2: Starting Price ($89.23/MWh). If subscription equals 100% of the initial capacity allocation for that product type, then the price decreases as follows:
- Months 3-4: Starting Price minus $4.00 (total $4.00 decrease from prior period) and, if subscription equals 100% of the initial capacity allocation for that product type , the price decreases as follows:
- Months 5-6: Starting Price minus $12.00 (total of $8.00 decrease from prior period) and, if subscription equals 100% of the initial

capacity allocation for that product type, the price decreases as follows:

- Months 7-8: Starting Price minus $24.00 (total of $12.00 decrease from prior period) and, if subscription equals 100% of the initial capacity allocation for that product type, the price decreases as follows:
- Months 9-10: Starting Price minus $40.00 (total of $16.00 decrease from prior period) and, if subscription equals 100% of the initial capacity allocation for that product type, the price decreases as follows:
- Months 11-12: Starting Price minus $60.00 (total of $20.00 decrease from prior period).

### 6.5. Assignment of Capacity to Three Products Incremental Release of Capacity and Three-MW Minimum to Start

In addition to allocating the program capacity among the three utilities, as discussed in Section 12.3, we direct the utilities to assign an equal portion of this allocated capacity to three product types over 24 months, i.e., baseload, peaking as-available, and non-peaking as-available. Any remaining unsubscribed capacity at the end of a two-month period is reallocated to the end of the 24 months, starting with a new period, Months 25-26. The MW should be spread out among Months 25-26 and further in a manner that reflects the initial allocations across Months 1-24. We adopt this design in an effort to stimulate the market for small renewable distributed generation by providing an adequate supply of available capacity to each product type in response to demand.[50]

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[50] SCE, CEERT, CALSEIA, and FuelCell Energy suggest a similar approach.

To implement this directive, each utility must divide the total program capacity by 12 and then assign one-third into each product type.

In the first adjustment period, i.e. Months 1-2, we require that each utility allocate a minimum of 3 MW to each product type. The same minimum obligation would apply to Months 25-26, if applicable. If dividing the total program capacity by 12 results in less than 3 MW being allocated to a product type per adjustment period, the utilities are to first allocate the minimum 3 MW per product type in the first adjustment period, and then equally allocate their remaining capacity among the three product types over the remaining 11 adjustment periods.

Each utility is directed to publicly notice the amount of capacity remaining in each product type on its website by the first business day of each two-month period.

This overall plan to allow IOUs to propose reallocation of capacity over 24 months (or perhaps further) is designed to minimize ratepayer exposure to a large number of non-competitively priced contracts while ensuring that some capacity is available for each product type, for which there is market interest.

### 6.6. Program Forums and Future Modifications to the Adjustment Mechanism

Since the adjustment mechanism adopted today is a new feature for the FiT Program, the utilities shall convene stakeholders within the first year of the program to solicit market experience with the price adjustment mechanism. Utilities shall also set up an on-line feedback mechanism with, for example, public questions and answers posted on the web.[51] In such a manner, utilities can gain continuous input to improve their programs. The utilities and market participants should address specific elements of the adjustment mechanism, such as the adjustment time period (e.g., two-months versus one-month or four months), the amount of the periodic price increase or decrease, and any other implementation aspect of the adjustment mechanism. To the extent that changes to the adjustment mechanism or other aspects of the program are needed to improve the program, the utilities may file a joint advice letter with the Commission seeking specific changes to the mechanism. Alternatively, Commission Staff may propose modifications to the adjustment mechanism through a draft resolution for consideration by the Commission.

### 6.7. Environmental Compliance Costs

Section 399.20(d)(1) refers to environmental compliance costs that the Commission must consider in setting a FiT tariff price and provides, in pertinent part, that: "The payment . . . 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."[52]

The costs referred to in this subsection are specifically described as "compliance costs." We view these compliance costs as distinct from general

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[51] SDG&E April 9, 2012 comments to proposed decision at 11.

[52] § 399.20(d)(1).

environmental societal values associated with particular forms of generation, including biogas and biomass. In some instances, parties relied on § 399.20(d)(1) to support their position that the Commission adopt an environmental adder or, in some other manner, incorporate into the FiT price a component to reflect specific environmental benefits of different generation technologies. For example, parties representing the biogas industry, including CEERT, AECA, Sustainable Conservation and others discussed the value of the reduction in emission of methane. Similarly, parties, including Placer County and others, representing the forest biomass industry explained the value of reduced air emissions from wildfires, mitigated fire suppression costs, and public safety benefits.

We support these renewable generation industries and their potential to contribute to the reduction of greenhouse gas emissions and improve air quality. In addition, we are impressed with the potential for the forest biomass industry to improve public safety through the reduction of wildfires.

Today, however, our focus is on implementing the legislative mandates of SB 32 and SB 2 1X, which direct us to incorporate into rates, among other factors, environmental compliance costs. The legislation does not address the cost savings related to general environmental benefits or increased public safety.

We make this decision with some reluctance as we understand that a price adder is needed, in some instances, to more closely reflect the costs of certain emerging industries. Furthermore, we have heard from parties that, in the absence of such an adder, the growth of these emerging technologies may be hindered.

However, we expect the price adjustment mechanism to account for varied resource costs within a product type and will monitor the program to ensure its success. In addition, we continue to be concerned about cost containment, generally, and in light of SB 2 1X have been closely reviewing cost containment in the context of overall renewable procurement in other aspects of this proceeding.

For this reason, at this point in time, we look toward the ratepayer indifference requirement in § 399.20(d)(4) and our goals of cost containment within the RPS Program for guidance on the extent to which the Commission should adopt a general environmental adder and find that, at this time, the ratepayer indifference clause of the statute and the directives on cost containment require us to refrain from general environmental adders even in those instances, such as biogas and forest biomass, where the environment and public safety qualities of the renewable generation technology is promising.

It is our intent, however, to encourage the growth of these technologies through the pricing mechanism we adopt today. The pricing mechanism is designed to respond to the market signals for different product types, including baseload. Biogas and forest biomass, presumably, will successfully bid into baseload in a manner that will further inform this Commission of the pricing requirements of those industries.

Turning now to the specific legislative directive in § 399.20(d)(1) and consideration of an adder to reflect the cost of environmental compliance, a few parties submitted evidence on this topic. We find that much of this data reflects general environmental costs and not, as specified by the statute, the cost of environmental compliance.

With regard to environmental compliance costs, we find that an adder for these costs is unwarranted, as the Re-MAT price should adjust to account for these costs. The rationale for a market-based price is that all of the generator's costs are included in the price because a generator would not bid something lower than its costs. In a market-based process, the seller determines the price it wishes to seek based on its understanding of the underlying project costs, and changes in those costs. (*Decision Adopting the Renewable Auction Mechanism* [D.10-12-048] (2010) __ Cal.P.U.C.3d __, p. 17 (slip op.).) In adopting the RAM, we found that a rational bidder would include all of its costs in its bid. (*Id*. at p. 85 [Finding of Fact 36].)

Given that all costs incurred by a generator are presumed included in a market-based price, we see no reason why environmental compliance costs should be treated differently from any other costs incurred by a generator. A generator should include all of its costs, including any environmental compliance costs, in its price for the Re-MAT. The Re-MAT price adjusts based on market conditions and, thus, should account for these costs. (See also, *Southern California Edison Company's Comments to Section 399.20 Ruling dated June 27, 2011*, dated July 21, 2011, p. 4 [market-based process would allow current and anticipated environmental costs to be included in the price]; *Clean Coalition Reply Comments on ALJ Ruling*, dated August 26, 2011, p. 31 [price adjustment mechanism could result in a price that includes environmental compliance costs].) Therefore, we find that the Re-MAT complies with the legislative directive in § 399.20(d)(1) regarding environmental compliance costs, and is also consistent with PURPA's requirements that rates for QFs be based on the utilities' avoided costs, rather than a generator's costs.

### 6.8. Resource Adequacy

Section 399.20(i) states "the physical generating capacity of an electric generation facility shall count toward the electrical corporation's resource adequacy requirement for purposes of Section 380."[53] Parties presented a range of proposals on how to implement this provision.

The utilities stated that to count a generator for resource adequacy, the CAISO must deem the generator deliverable but, for this to occur, the CAISO must complete a deliverability study, which takes almost two years to complete and could result in costly system upgrades.[54] Notably, at this time, generators interconnecting through the presently effective Tariff Rule 21 do not have the option to apply for a deliverability study.[55]

Based on the view that a deliverability study is overly burdensome from a time and cost perspective for very small generators, most parties and the Commission's Staff recommended rejecting the utilities' proposal. Specifically, in order to be studied for deliverability, a generator must request deliverability from the CAISO when it seeks interconnection. The CAISO only performs deliverability studies once a year and a generator must apply by March 31 in order to be studied that year. The deliverability study consists of two phases and application fees and deposits to stay in the study process. The total study

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[53] Section 380 provides, in part, that the Commission, in consultation with the CAISO, shall establish resource adequacy requirements for all load-serving entities.

[54] The CAISO, not the Commission, determines whether a project obtains resource adequacy.

[55] Pursuant to the revisions to Rule 21 proposed by the settling parties in R.11-09-011, the tariff would remain an energy-only tariff and would expressly state that an interconnection applicant under Rule 21 (revised) is not prohibited from applying for an assessment under the utility's applicable wholesale distribution access tariff. (*See Motion for Approval of Settlement Agreement Revising Distribution Level Interconnection Rules and Regulations*, Proposed Revised Rule 21 at Section E.2.b.iii.

process can take two years and the study may require costly upgrades to the transmission system in order to make the generator fully deliverable. Because these requirements are burdensome for small generators, on May 16, 2012, the CAISO Board of Governors approved the Resource Adequacy Deliverability for Distributed Generation initiative, which will provide an alternative path to deliverability for distributed generation.[56] Those changes will not apply until the 2013-2014 Resource Adequacy year and the success of the revisions will not be known until much later.

In November 2011 comments, PG&E proposed a solution to address, in the near term, the concerns related to requiring a deliverability study but, at the same time, ensure compliance with § 399.20(i). PG&E recommends the Commission establish time-of-delivery factors for generators that do not provide resource adequacy. We find PG&E's proposal reasonable since it allows generators to choose to pursue a deliverability study if they want to receive a higher time-of-delivery adjusted price. It also removes the burden of pursuing deliverability if the costs and timing are too burdensome.

Moreover, since the deliverability study process can occur over a long period of time, generators can convert to full deliverability after their online date and receive the higher time-of-delivery factors at that time. As a result, full

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[56] California Independent System Operator, *Resource Adequacy Deliverability for Distributed Generation Draft Final Proposal* (March 29, 2012) (available at: http://www.caiso.com/Documents/DraftFinalProposal-Deliverability-DistributedGeneration.pdf). The Commission Staff collaborated with the CAISO in developing this proposal and fully supported the proposal before the CAISO Board of Governors.

commercial deliverability status should not be a condition precedent for any generator seeking a contract under the § 399.20 FiT Program.

Accordingly, PG&E, SCE, and SDG&E shall offer two sets of time-of-delivery factors: one for generators that do not provide resource adequacy and another for generators that do provide resource adequacy. PG&E, SCE, and SDG&E shall add a provision reflecting delivery factors to the FiT Program standard form contract and/or tariff that is being developed in this proceeding in accordance with the schedule set forth in the January 10, 2012 ALJ ruling. The Commission will review this provision submitted by the utilities and, in a separate decision accept, reject, or modify the provision. Related FiT tariff modifications will also be addressed in this separate decision.

### 6.9. Define "Strategically Located"

Today's decision implements the requirement that generators participating in the § 399.20 FiT Program be "strategically located."

Section 399.20(b) contains four specific criteria that an electric generation facility must meet to sell electricity under the § 399.20 FiT Program. The third criterion is that the generation facility be "strategically located." The concept set forth in this provision is different than the concept in subsection (e) of § 399.20, which describes the value of a project's electricity as potentially influenced by its location on the distribution network.[57] In contrast, the specific statutory

[57] Subsection (e) of § 399.20 states, in pertinent part: "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."

provision in subsection (b) is a prerequisite to participation in the program and provides as follows: The electric generation facility 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."[58]

This provision, in its current format, was first incorporated into § 399.20 by SB 380 but existed, in a more limited manner, in the original legislation, AB 1969.[59] On August 5, 2011, SCE commented on the meaning of this statutory provision. Specifically, SCE suggested that the generator interconnect at one of the preferred locations as identified on SCE's circuit map posted on its website. The Renewable FiT Staff Proposal offered an alternative to SCE's suggestion. Specifically, the Commission's Staff suggested that generators be interconnected to the distribution system and not exceed the minimum load of the circuit when generating electricity. Both of these recommendations intend to target generators as eligible for the program that do not have impacts on the transmission system.

We find that the statutory language means that a generator must be interconnected to the distribution system, as opposed to the transmission system, and must be sited near load, meaning sited in an area where interconnection of

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58 § 399.20(b)(3).

59 AB 1969 enacted § 399.20(f) which stated: "Public water and wastewater facilities are strategically located and interconnected to the electric transmission systems in a manner that optimizes the deliverability of electricity generated at those facilities to load centers."

the proposed generation to the distribution system requires $300,000 or less of upgrades to the transmission system.

In making this determination, we rely on our policy guideline to use existing transmission and distribution infrastructure efficiently. We further point out that our policy guideline is grounded in the legislative intent set forth in SB 32 (Sec. 1) which emphasizes the importance of encouraging the location of clean generation close to load centers in order to meet increases in demand for electricity.

To implement our interpretation of subsection (b)(3), we find that if a project's most recent interconnection study shows that the project requires more than $300,000 of transmission system network upgrades, that project is no longer eligible for the § 399.20 FiT Program[60] As described in Section 10, below, one project viability criteria is that a project must have completed its system impact study or cluster study phase 1 study (the first of two interconnection studies). Therefore, the generator will have information on whether a project qualifies as "strategically located" before signing a power purchase agreement. We expect generators to use the utilities' Interconnection Maps, available to the public and online, to locate sites that have a low likelihood of transmission impacts.

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[60] This figure is based on the highest per MW costs of the levelized median total upgrade costs of solar PV projects up to 3 MW from the Renewables Portfolio Standard Quarterly Report. Third Quarter 2011 at 10-11. This report can be found at: http://www.cpuc.ca.gov/NR/rdonlyres/2A2D457A-CD21-46B3-A2D7-757A36CA20B3/0/Q3RPSReporttotheLegislatureFINAL.pdf.

Furthermore, we find that this prerequisite, "strategically located," applies to all generators seeking a contract under the § 399.20 FiT Program.

Accordingly, PG&E, SCE, and SDG&E shall add to the § 399.20 FiT Program standard form contract and/or tariff that is being developed in this proceeding in accordance with the schedule set forth in the January 10, 2012 ALJ ruling the prerequisite that generators must be "strategically located." This means that the generator be (1) interconnected to the distribution system, as opposed to the transmission system, and (2) 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. Such a provision shall be presented to the Commission for consideration in accordance with the schedule set forth in the January 10, 2012 ALJ ruling. The Commission will review this provision submitted by the utilities and in a separate decision accept, reject, or modify the provision. Related FiT tariff modifications will also be addressed in this separate decision.

### 6.10. Ratepayer Indifference

In March 2011 briefs and comments filed in July, August, and November 2011, parties addressed the meaning of the requirement under § 399.20 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."[61] Some parties, including CEERT, stated that ratepayers are indifferent to any avoided cost rate. Other parties found ratepayers to be

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[61] § 399.20(d)(4).

indifferent to any rate that is value based. These parties include CALSEIA, Agricultural Energy Consumers Association (AECA)/Inland Empire Utilities Agency, and Clean Coalition. Clean Coalition also cited the Commission's application of a customer indifference provision in the implementation of AB 1613.[62] Other parties, such as SCE, suggest that a market-based pricing methodology, which adjusts to reflect changes in the market, will ensure ratepayer indifference by establishing a price based on the market, thereby containing costs and ensuring maximum value to the customer and utility.

Notably, in D.10-12-048, we favored market-based pricing as a means of protecting ratepayers, stating that: "Administrative determination of contract prices is less likely to be as responsive to cost changes than is a seller determining the price it wishes to seek in an auction based on its understanding of the underlying project costs, and changes in those costs."[63] Similarly, we find today that Re-MAT, a market-based pricing methodology, best ensures ratepayer indifference under § 399.20(d)(4). A market-based approach is in the best interest

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62 "In light of these considerations, we find that customer indifference under AB 1613 would not be achieved if the price paid under the program only reflected the market price of power. As discussed, since customers who are not utilizing the eligible Combined Heat and Power system will receive environmental and locational benefits from these systems, the price paid for power should also include the costs to obtain these benefits." (D.09-12-042 at 17.)

63 D.10-12-048 at 16-17.

of California electricity customers. We now know that the state's renewable energy market has matured and prices have decreased.[64]

The market-based pricing methodology adopted today allows customers to realize the benefits of changing market conditions that result in potentially lower costs. In addition, it allows generators to set the market price through the bidding process, which theoretically will ensure the price is neither too high nor too low but, instead, will be reasonable to cover the generator's costs and encourage broad participation in the market. In contrast, administratively-determined pricing is static and, as a result, can result in pricing being either too high, leading to windfalls for project developers and unnecessarily high procurement costs for customers, or pricing that is too low, preventing program subscription. These scenarios based on an administratively-determined price do not achieve ratepayer indifference to the extent achieved by Re-MAT.

Accordingly, we find that the pricing mechanism adopted today complies with "ratepayer indifference" set forth in § 399.20(d)(4) by reflecting the supply and demand of the renewable generation market.

### 6.11. First-Come-First-Served

Section 399.20(f) states that "[a]n electrical corporation shall make the tariff available … on a first-come-first-served basis."

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64 *See, e.g.*, DRA June 21, 2011 comments (noting that recent changes in the California renewable energy market make it reasonable to transition from basing the Section 399.20 tariff price on the MPR to a net surplus compensation rate). In contrast, Sustainable Conservation notes that some technologies, such as bioenergy, are still maturing and have not necessarily experienced cost decreases.

Section 399.20(f) discusses the obligation of the utilities, and does not discuss the Commission's authority to impose pricing, procurement, or other program requirements for the FiT. The Commission has broad authority over public utilities, including authority over the utilities' resource portfolios and procurement planning, and in implementing the RPS Program. (See, e.g., Cal. Const., art. XII, § 6; Pub. Util. Code, §§ 399.11 et seq., 454.5, 701.) The Commission has the authority to act even in cases where there is no express statutory authorization so long as the additional power and jurisdiction the Commission exercises are cognate and germane to the regulation of public utilities, and do not contravene or disregard an express legislative directive. (Pub. Util. Code, § 701; *Consumer Lobby Against Monopolies v. Public Utilities Com.* (1979) 25 Cal.3d 891, 905-906; *Assembly v. Public Utilities Com.* (1995) 12 Cal. 4th 87, 103.) Therefore, the Commission is not restricted from adopting additional program requirements for the FiT, so long as the imposition of these requirements does not contravene other statutory requirements.

In order to comply with section 399.20(f), the utilities should make their respective tariffs, which incorporate any program requirements required by statute or by the Commission, available on a first-come-first-served basis. Among other things, the utilities' tariffs must incorporate the pricing mechanism adopted pursuant to section 399.20(d). The utilities' tariffs should also incorporate the requirement that an equal portion of their allotted capacity be assigned to the three product types, baseload, peaking, and as-available. We find that this program requirement is warranted based on the legislative directive in section 399.20(d)(2)(C) that the Commission take into consideration the value of different electricity products in establishing a pricing methodology for the FiT.

## 7. Increase the Size of Eligible Facility to 3 MW

This decision implements the statutory amendments by increasing the maximum size of the eligible facility to 3 MW.

As originally enacted by AB 1969, § 399.20(b)(2) applied to facilities with an effective capacity of not more than 1.5 MW. In D.07-07-027, the Commission implemented a program under § 399.20 with a capacity limitation of 1.5 MW. SB 32 increased the capacity to 3 MW but the Commission has not yet implemented this change. SB 2 1X made no change to this provision of § 399.20.

SunEdison, Silverado Power, Solar Alliance, and Vote Solar Initiative support increasing the project eligibility to 3 MW and either find no potential reliability issues or suggest any system impact issues to the electrical grid will be addressed through the interconnection process under Tariff Rule 21 or the applicable federal rules. PG&E also supports increasing the capacity limitation of the program and indicates that it is unaware of any existing reliability issues, although increased reliance on this program and others may raise reliability concerns in the future. DRA supports the increase as offering an opportunity for economies of scale and therefore lower pricing.

Clean Coalition supports increasing the capacity beyond the 3 MW capacity limitation in the statute and suggests the Commission, on its own authority, further increase the capacity limitation to 5 MW. Clean Coalition points to expedited interconnection processes that apply to projects up to 5 MW to justify its request. Joint Solar Parties support an increase to 5 MW. Sustainable Conservation points to the benefits to the grid offered by the increased project size and to developers in terms of financial viability.

Several parties raise concerns about opening the program to larger generators. SDG&E states that to increase the size of eligibility, the Commission would need to: (1) ensure that generators continue to carry the costs of electrical system upgrades; (2) subject projects larger than 1.5 MW to the same security requirements as bidders in the standard RPS solicitation; (3) adopt delivery guarantees and damage provisions to allow the utility to manage its resource planning; and (4) apply the CAISO penalty provisions to ensure developers provide accurate schedules. SCE generally agrees with SDG&E that increased capacity will result in increased costs for electrical system upgrades.

CALSEIA states that the increase in size of the eligible facility should occur gradually to promote projects located close to load centers and that the utilities should be authorized to request bidders to modify project size to facilitate increased grid reliability. CALSEIA requests the Commission direct the electric utilities to work cooperatively with potential distributed generation projects to assist developers in identifying locations where the addition of renewable generation of a particular size will improve system reliability. CALSEIA explains that coordination will assist developers with the overall success of project development at the lowest costs.

We find that increasing the maximum project size to 3 MW is reasonable based on the Commission's obligation to implement the provisions of the statute and note that any reliability concerns triggered by individual generating facilities are appropriately identified and mitigated within the interconnection process. We decline to adopt a 5 MW program size limitation since the plain language of § 399.20(b)(1) clearly defines the effective capacity of not more than 3 MW.

We disagree with CALSEIA's recommendation to increase the size of eligible facilities gradually until the size of 3 MW is reached. We find no connection between a gradual increase in project size and CALSEIA's objective to encourage generation to locate near load centers. We do, however, find that today's implementation of the requirement that generation be "strategically located," per the statute, will achieve the goal of encouraging generation to locate near load centers. The meaning of "strategically located," is further discussed in Section 6.9. Furthermore, neither CALSEIA nor any other party provided evidence that increasing the size to 3 MW will negatively impact grid reliability. For these reasons, we do not adopt CALSEIA's recommendation to gradually permit an increase in project size.

Sierra Club makes a brief argument that the FiT maximum project size should be determined by "the amount of generating capacity that can be reliably generated." Sierra Club, however, does not explain how to determine the amount of capacity that can be "reliably generated" nor does Sierra Club state the benefits of such a policy. Accordingly, we do not adopt Sierra Club's proposal but note that Sierra Club's comments highlight the need for additional clarity around what facilities fall within the 3 MW size limit. Today we clarify that the 3 MW AC size limitation corresponds to the nameplate capacity of the facility.

We note further that the 3 MW size is aligned with the general framework of the proposed settlement revising Rule 21 (filed in R.11-09-011 on March 16, 2012). As we have stated in R.11-09-011, exporting generating facilities do not have a clear path to interconnection under the presently effective Rule 21.[65] The May 16, 2012 settlement's proposed revisions to Rule 21 would expressly permit exporting facilities sized up to 3 MW in SCE's and PG&E's service territories and

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[65] R.11-09-011 at 4-5.

1.5 MW in SDG&E's service territory to be evaluated under the Fast Track process.[66] While the Commission has not yet acted on the proposed interconnection settlement in R.11-09-011, the proposed Fast Track size limits would advance the statutorily required "expedited interconnection" for resources in this program.[67]

Accordingly, PG&E, SCE, and SDG&E shall add a provision reflecting the increase in eligible generator projects to 3 MW to the FiT Program standard form contract and/or tariff that is being developed in this proceeding in accordance with the schedule set forth in the January 10, 2012 ALJ ruling. The Commission will review this provision submitted by the utilities and, in a separate decision accept, reject, or modify the provision. Related FiT tariff modifications will also be addressed in this separate decision.

## 8. Prohibition Against "Daisy-Chaining" to Evade Project Size Limitations

TURN, CUE, SunEdison, CALSEIA, and other parties raise the concern that project developers may break up larger projects into smaller pieces or "daisy-chain" in order to evade the size restriction. TURN and CUE suggest that utilities be given the authority to deny a tariff request pursuant to § 399.20(n) if the project appears to be part of a larger overall installation by the same company or consortium in the same general location. TURN also suggests that the Commission direct the utilities to add a provision titled "Seller

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[66] *Motion for Approval of Settlement Agreement Revising Distribution Level Interconnection Rules and Regulations*, Proposed Revised Rule 21 at Section E.2.b.i.

[67] § 399.20(e).

Representation" that requires the seller to attest that the project represents the only project being developed by the seller on any single or contiguous piece of property.

We agree with TURN, CUE, CALSEIA, and SunEdison that additional measures must be taken to prevent daisy-chaining and agree with the concerns raised regarding daisy-chaining to evade the project size restrictions.

Accordingly, the utilities shall add a provision titled, generally, "Seller Representation" to the § 399.20 FiT Program standard form contract and/or tariff that is being developed in this proceeding in accordance with the schedule set forth in the January 10, 2012 ALJ ruling. The Commission will review this provision submitted by the utilities and in a separate decision accept, reject, or modify the provision. Related FiT tariff modifications will also be addressed in this separate decision. This provision shall, at a minimum, require the seller to attest that the project represents the only project being developed by the seller on any single or contiguous piece of property. This provision shall also give utilities the authority to deny a tariff request pursuant to § 399.20(n) if the project appears to be part of a larger overall installation by the same company or consortium in the same general location. Lastly, this provision shall permit generators to contest a denial under § 399.20(n) through the Commission's standard complaint procedure set forth in the Commission's Rules of Practice and Procedure.

## 9. Eliminate Overlap of the Commission's RAM Program and § 399.20 Program

As discussed in more detail below, any overlap between the RAM Program adopted in D.10-12-048 and the § 399.20 FiT Program is eliminated. Under D.07-07-027, the Commission's § 399.20 FiT Program has, until today, only applied to facilities up to 1.5 MW. However, this decision increases the size of the eligible facilities under the FiT Program to 3 MW.[68] The RAM Program, as adopted in D.10-12-048, applies to renewable generation from 1 MW to 20 MW. Therefore, unless today's decision modifies the RAM Program, these two programs will overlap for projects 3 MW and under.

Some parties, including SCE and TURN, expressed concern regarding the overlap of these two renewable programs and the potential for gaming of the price of the two programs for projects of 3 MW and under. For example, as SCE points out, a bidder in the RAM Program who is eligible under § 399.20 would never bid below the FiT price because it knows it could go back to the FiT Program and receive that price. Moreover, a bidder would have more ability to inflate a bid in the RAM Program because it would be able to fallback to the FiT Program.

We find that the most effective means of preventing potential gaming is to prohibit generators with a nameplate capacity of 3 MW[69] and under and that meet other eligibility criteria for the FiT Program, from participating in the RAM Program if the capacity for the relevant FiT product type has not yet been reached. This approach was recommended by SCE and TURN. This restriction will also eliminate a duplicative procurement mechanism for these small renewable generators. The potential duplication would also increase

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[68] As originally enacted by AB 1969, § 399.20(b)(2) applied to facilities with an effective capacity of not more than 1.5 MW. In D.07-07-027, the Commission implemented a program under § 399.20 with a capacity limitation of 1.5 MW. SB 32 increased the capacity to 3 MW.

[69] The 3 MW AC size limitation corresponds to the nameplate capacity of the facility.

administrative burdens and complicate the implementation process for program participants and the Commission.

Accordingly, within 90 days of the effective date of this decision, PG&E, SCE, and SDG&E shall file a Tier 1 Advice Letter restricting RAM to generators with a nameplate capacity of greater than 3 MW. This change will not affect the upcoming RAM auction scheduled to close in May 2012 but will take effect in time for the third RAM auction scheduled for the end of 2012.

## 10. Project Viability Criteria for § 399.20 Feed-In Tariff Program

In March 2011 briefs, SunEdison, CALSEIA, and Joint Solar Parties suggested that the Commission adopt a means to ensure that only viable projects participate in the program. The Clean Coalition, FuelCell Energy, CEERT, and Silverado Power agreed that it is a critical issue to target viable projects since the amount of capacity in the § 399.20 FiT Program is limited. These parties stated that increasing the viability of contracts executed pursuant to this program will allow for more efficient management of the limited program capacity and benefit the market by reducing speculative contracts.

SunEdison recommends establishing project viability criteria similar to those relied upon in the RAM Program. Agreeing with the need for project viability criteria, CALSEIA requests that the Commission adopt rules to prevent generators from taking advantage of the "first-come-first-served" rule to gain priority while projects may be less than viable. Likewise, the Renewable FiT Staff Proposal recommends project viability criteria, consistent with suggestions by parties. The Staff Proposal and other parties recommend the following project viability criteria:

1) <u>Bid fee:</u> $2/kW bid fee;

2) Interconnection: System Impact Study, Phase I study, or passed the Fast Track screens or supplemental review;

3) Site Control: Attest to: 100% site control through (a) direct ownership, (b) lease, or (c) an option to lease or purchase that may be exercised upon contract execution;

4) Development Experience: Attest that: one member of the development team has (a) completed at least one project of similar technology and capacity or (b) begun construction of at least one other similar project;

5) Online Date: 24 months with one 6-month extension for regulatory delays;

6) Seller Concentration: An individual seller may not subscribe to more than 10 MW of capacity across the program. CALSEIA and PG&E suggest a seller concentration cap of 10 MW per seller. Staff agrees that there should be limit, but recommends a different metric. Staff proposes a seller be limited to 25% of an IOU's total capacity cap; and

7) Commercialized Technology: Attest that: project is based on commercialized technology with at least two installations in the world.

This decision adopts the above-noted project viability criteria 1 through 6. No viability criterion is adopted for commercialized technology (number 7 above). We find that the project viability criteria adopted today will assist in ensuring that projects seeking to participate in the FiT Program will come online, which supports our fifth policy guideline: increase probability of successful projects by establishing project viability criteria.

This decision adopts a seller concentration limit of 10 MW per seller because of the limited number of MWs available for the program. The definition of seller should be further explored in the standard contract phase of this proceeding. We also envision the other program requirements, such as "strategically located" and the three product types, which are discussed elsewhere in this decision, to encourage a diversity of sellers and technologies in the program.

The decision also does not adopt a requirement that the project be based on commercialized technologies. While we expect most projects to utilize commercialized technologies, the FiT Program seeks to provide an opportunity for emerging technologies to develop on a small scale and at a reasonable price. No reason exists to preclude new or emerging technologies from the FiT Program by adopting a commercialized technology requirement.

Accordingly, PG&E, SCE, and SDG&E shall add a provision reflecting the adopted project viability criteria to the § 399.20 FiT Program standard form contract and/or tariff that is being developed in this proceeding in accordance with the schedule set forth in the January 10, 2012 ALJ ruling. The Commission will review this provision submitted by the utilities and, in a separate decision accept, reject, or modify the provision. Related FiT tariff modifications will also be addressed in this separate decision.

## 11. Applicability of the § 399.20 Feed-in Tariff Program to Small Electric Utilities

This decision implements SB 380 and SB 32 by removing electric corporations with less than 100,000 service connections from the § 399.20 FiT Program.

SB 380 amended § 399.20 by adding subsection (h) which authorizes the Commission on a discretionary basis to modify or adjust the requirements of § 399.20 for any electrical corporation with less than 100,000 service connections. SB 32 recasts this same provision by combining it with subsection (c) and leaving the language unchanged. SB 2 1X makes no changes to this provision.

In response to various ALJ rulings, parties provided comments on implementation of this provision. The California Association of Small and Multi-Jurisdictional Utilities (CASMU)[70] requests that the Commission rely on § 399.20(c) to exempt electric corporations with less than 100,000 service connections from the requirements of § 399.20. CASMU indicates that its members operate with between approximately 700 and 46,000 service connections within the state. Some of these utilities provide additional service connections in other states. CASMU further indicates that the combined obligation of all CASMU members under the existing § 399.20 FiT Program, as implemented by D.07-07-027, is small, only 0.599% or 1.497 MW and that under SB 32 with the increased program size, this total would only increase to approximately 3 MW, which CASMU argues is still very low. The § 399.20 FiT Program offered by CASMU members remains limited in other respects as these utilities currently only offer feed-in tariffs for water and wastewater facilities and not the expanded customer base authorized by D.07-07-027. FuelCell Energy supports an exemption because the costs associated with administering this program outweigh the proportionate share of participation.

Other parties, such as SunEdison, CALSEIA, and Sustainable Conservation, suggest that participation by small electric corporations remain

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[70] CASMU includes Bear Valley Electric Service (U913E), a division of Golden State Water Company, California Pacific Electric Company, LLC (U933E) dba Liberty Energy, California Pacific Electric Company, and PacifiCorp (U901E) dba Pacific Power. CASMU group no longer includes Mountain Utilities (U906E) as D.11-06-032 approved a sale and transfer of control of assets and relieved Mountain Utilities of its obligation to provide public utility electricity service.

voluntary because, although small, it continues to be an important component of reaching the state's 33% renewable goal. The largest electric corporations did not present a unanimous position on this topic. PG&E and SDG&E did not comment. SCE claims that the smaller electric corporations are legally required to participate because the exemption in subsection (c) just applies to parts of the program, not the entire program.

We find that the plain language of § 399.20(c) provides the Commission with authority to modify the program as applied to small electrical corporation in a manner that includes fully removing these utilities from the program. The language permits the Commission to "modify or adjust" the requirements of § 399.20 as applied to small electrical corporations. We find that modifying the program by removing these utilities is justified because the costs of administering this program for the smaller utilities outweigh any potential benefit from their contribution, of approximately 3 MW, to the overall program.

We disagree with parties, such as SCE, to the extent they claim that modification does not mean exempting these utilities from the program. Subsection (c) provides the Commission with latitude in interpreting this provision and, with these smaller utilities only contributing approximately 3 MW, we find it reasonable to relieve them from the administrative burdens associated with the program. Currently, no customers are served under these tariffs. These smaller utilities are not prohibited from seeking authority to provide a voluntary program, separate from the FiT Program, consistent with all applicable laws and regulations.

Accordingly, within 90 days of the effective date of this decision and pursuant to § 399.20(c), electrical corporations with less than 100,000 service connections within this state shall file Tier 1 Advice Letters withdrawing their tariffs relevant to the § 399.20 FiT Program.

## 12. Statewide Capacity Program Cap Increased to 750 MW and Allocation of Proportionate Share to Commission Regulated Utilities

This decision implements the statutory amendments by increasing the program cap to 750 MW and allocates the proportionate share of the 750 MW (with a proportionate share designated for publicly owned utilities) to the three largest electric utilities regulated by the Commission. The allocations are made in accordance with the methodology adopted in D.07-07-027, as follows: PG&E 218.8 MW; SCE 226 MW; and SDG&E 48.8 MW, for a total of 493.6 MW.[71] We make no determinations regarding the implementation of § 399.20(f) to the extent it refers to publicly owned electric utilities provided for under § 387.6.

As originally enacted by AB 1969, § 399.20(e) required each electric corporation to offer service or tariffs under this code section until it had met its "proportional share" of the total megawatts subject to § 399.20. The total amount subject to § 399.20(e), as originally enacted, was 250 MW. The Commission implemented a program with a 250 MW cap in D.07-07-027 for public water and wastewater customers. In implementing the 250 MW cap, D.07-07-027 allocated these megawatts among the utilities regulated by the Commission for public water and wastewater customers. D.07-07-027 and D.08-09-033 expanded the

[71] Based on subscriptions to date, the remaining MWs in the FiT Program are as follows: PG&E – 111 MW; SCE – 149.7 MW; SDG&E – 30 MW.

program to all customers in the service territories of SCE, PG&E, and SDG&E, and allocated an additional 248.4 MW to these customers.

These utilities were, in turn, responsible for entering into contracts with generators for, at a minimum, the amount of megawatts allocated to them under D.07-07-027 and D.08-09-033. SB 380 increased the program cap to 500 MW and SB 32 increased the program cap again from 500 MW to 750 MW. At that time, the Commission did not implement these increases by modifying its existing program. The existing program remained capped at 250 MW for public water and wastewater customers and 248.4 MW for all other customers in the large utilities' service territories. SB 32 renamed the relevant subsection from subsection (e) to subsection (f) and included local publicly owned electric utilities. SB 2 1X makes no further modifications to § 399.20(f).

Below we discuss implementing the 750 MW program cap, the existing allocation methodology adopted in D.07-07-027, our allocation methodology adopted today going forward, and several related issues raised by parties.

### 12.1. Program Cap of 750 MW

Most parties, including CWCCG, Silverado Power, DRA, PG&E, SCE, and SDG&E, support increasing the program cap to the statutory limit of 750 MW. We agree and, accordingly, consistent with the statutory directive in § 399.20(f), increase the program capacity from the existing amount, as implemented in D.07-07-027, of 250 MW to 750 MW. Many parties, even those that support the increase to 750 MW, raise various questions related to implementing the increased cap. We address these various questions below.

We do not adopt the recommendation by some parties, including Vote Solar Initiative, Solar Alliance, Sierra Club, and Clean Coalition, to increase the cap beyond 750 MW. The Legislature created a specific program under § 399.20

limited to 750 MW and this program is, notably, a must-take obligation by utilities and the renewable generation procured under this program has cost implications for ratepayers. Therefore, today we set as our goal implementing the plain language of the statute and the 750 MW cap noted therein. Our decision today also rests upon our goal of achieving "ratepayer indifference" and cost containment within the program.

We clarify, however, that for amounts that exceed a utility's proportionate share of the 750 MW cap, the statute does not prohibit utilities and generators from voluntarily entering into contracts. The Commission would review these contracts under the standard of review used for general renewable procurement.

We also clarify that the 750 MW cap applies on a statewide basis. As described in § 399.20(f), 750 MW is a "statewide" cap, not a service territory cap or a cap that solely applies to Commission regulated utilities. As such, based on the clear statutory language, we reject the argument made by CEERT and others that the entire 750 MW cap only applies to IOUs and that publicly owned electric utilities are subject to a separate cap. Under the provisions of the statute, the 750 MW is to be split on a proportional basis between investor owned and publicly owned electric utilities.

Furthermore, other parties, such as Clean Coalition and CEERT, suggest that the 750 MW cap is an amount in addition to the existing 250 MW cap enacted under AB 1969 and implemented by the Commission in D.07-07-027. We disagree. Again, we find that the plain language of the statute establishes a total cap of 750 MW for the entire § 399.20 Program and, accordingly, does not provide for an additional cap of 250 MW.

Some parties, including SunEdison and Joint Solar, recommend that the Commission incrementally release available capacity in the program over a two-year period, with a new release every six months. We agree, in part, with this recommendation. This issue is addressed within the pricing proposal adopted by today's decision.

Various parties, including Vote Solar Initiative and FuelCell Energy, raise issues related to the treatment of projects that are already under contract in the existing AB 1969 program. We find that all capacity already under contract from the existing § 399.20 FiT Program must be subtracted from each utility's total capacity allocation. Each utility is to subtract this capacity from its total capacity allocation prior to allocation among the three product types. If a contract is terminated at a future date, then the utility is obligated to re-contract for that capacity.

### 12.2. Capacity Allocation Methodology in Decision 07-07-027 Adopted

This decision adopts the existing allocation methodology previously adopted by the Commission in D.07-07-027 when implementing AB 1969.

In D.07-07-027, the Commission determined that 250 MW, which represented the statewide capacity requirement under § 399.20 (before SB 32), be allocated according to coincident peak demand, meaning the regulated utilities share of total system-statewide peak.

In general, parties support retaining the existing allocation methodology while updating the coincident peak demand data to at least 2009. Some parties, however, support a different methodology. SCE suggests relying on each utility's prior three year historical peak load compared to the sum of all utilities' peak load because average historical data will mitigate year-to-year volatility. SCE also suggests reliance on actual peak load, rather than coincident peak to again, provide more reliable comparisons. PG&E suggests relying on a utility's actual retail peak demand divided by the total statewide peak demand.

We find these suggestions have merit but do not offer sufficient benefits to warrant a change in the existing allocation methodology. The current methodology is very similar to the above suggestions and, in the interest of consistency and administrative simplicity, we find that retaining the existing allocation methodology going forward is reasonable.

Several factors must be considered in applying the existing allocation methodology to the current situation. At the time the Commission issued D.07-07-027, § 399.20 did not require participation by publicly owned electric utilities. Now, under the amendments to § 399.20 enacted by SB 32, the program's statewide cap of 750 MW applies to IOUs and publicly owned electric utilities. The addition of publicly owned utilities will impact the amount of capacity allocated to Commission-regulated utilities.

### 12.3. Allocated Amount - Investor Owned Utilities

Table 1
Share of Investor Owned Utilities § 399. 20(f) Capacity Allocation – 750 MW Statewide Program Cap

| **Electrical Corporation** | **Share of 750 MW** | **Capacity Allocated** |
|---|---|---|
| Pacific Gas and Electric Company | 29% | 218.8 MW |
| Southern California Edison Company | 30% | 226 MW |
| San Diego Gas & Electric Company | 6% | 48.8 MW |
| Publicly Owned Electric Utility (§ 387.6) | See discussion herein on § 387.6 | See discussion herein on § 387.6 |

To determine the above, the Commission relied upon the following data:

(1) 2010 Coincident Peak-Hour Demand:[72]

SDG&E: 3,953 MW
PG&E: 17,742 MW
SCE: 18,342 MW

(2) Total Statewide Demand:

Summer 2010 Peak: 60,797 MW[73]

(3) Determining Each Utility's Share:

Formula: 2010 Coincident Peak-Hour Demand/Total Statewide Demand = § 399.20 FiT Program Percentage x Program Cap = Program Share

SDG&E: 3,953 MW/60,797 = 6% x 750 = 48.8 MW
PG&E: 17, 742 MW/60,797 = 29% x 750 = 218.8 MW
SCE: 18,342 MW/60, 797 = 30% x 750 = 226 MW

Total Investor Owned Utilities Share: 48 + 218.8 + 226 = 493.6 MW

(4) Former § 399.20 FiT Program Allocation (with a 500 MW program cap):

SDG&E: 8% or 20 MW
PG&E: 41% or 209.2 MW

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[72] *Information for most recently available year of 2010 from*: Utility Capacity Supply Plans (2011) http://energyalmanac.ca.gov/electricity/s-1_supply_forms_2011/ (scroll through excel spreadsheets for each utility's data).

[73] *Information for most recently available year of 2010 from*: Summer 2010 Electricity Supply and Demand Outlook, CEC-200-2010-003, at 3 (May 2010) http://www.energy.ca.gov/2010publications/CEC-200-2010-003/CEC-200-2010-003.PDF

SCE: 49% or 247.6 MW

### 12.4. Set Aside of Allocated Capacity for Specific Technologies

We decline to adopt a set-aside (or carve-out) of capacity for specific technologies. AECA, CWCCG, FuelCell Energy, Sustainable Conservation, GPI, and CEERT support a set-side (or carve-out) of capacity for specific technologies. The recommendations vary.

AECA recommends that the Commission reserve 150 MW of the total 750 MW program cap for biogas generation projects at California dairy, food processing, and wastewater treatment facilities. Sustainable Conversation and GPI offer a similar recommendation. FuelCell Energy recommends that 20% of each utility's share of the 750 MW total be set aside for biogas. AECA's recommendation to reserve 150 MW is tied to a pricing proposal for biogas that is intended to make this initial 150 MW of biogas projects more competitively priced. This proposal is also tied to AECA's broader recommendation that the Commission adopt processes to encourage the growth of the biogas industry. CWCCG also supports a set-aside of the program cap for biogas as a means to spur industry growth.

Other parties, such as, PG&E, SCE, SDG&E, TURN, DRA, and Constellation NewEnergy, Inc. oppose the technology-specific set-aside recommendations. These parties assert that nothing in the statute allows for technology specific set-asides. They further point out that the Legislature had the opportunity to create a set aside but did not and, instead, created a program for all eligible resources under 3 MW. These parties urge the Commission to create a level playing field for equal participation in the program by all eligible technologies.

Today we decline to adopt a set aside for any specific technology. As created by the Legislature, the § 399.20 Program is intended to encourage electrical generation from eligible renewable energy resources but there is no statutory provision that directs us to consider a set-aside for any particular technology. To the extent that there is no statutory requirement requiring technological set-asides for the § 399.20 Program, it is within our authority and discretion to determine how to implement the program. We decline to adopt technological set-asides at this time because it is not required by statute, and because, as with technology-specific pricing discussed in Section 5.3, above, we find that technological-set asides are not consistent with our policy guidelines for the FiT Program.

However, as discussed previously, we seek to support the development of different renewable technologies, and, therefore, we adopt three product types within today's expanded FiT Program. This provides benefits to the IOUs because they can procure FiT resources consistent with their need and the value that each product provides. In addition, consistent with § 399.20(d)(2)(C), it dedicates a certain portion of the capacity allocation to each product type.[74] The Re-MAT pricing mechanism could benefit bioenergy, biogas, forest biomass, and the other technologies because it allows renewable resources to compete against other similarly-valued renewable resources, rather than the entire renewable

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[74] § 399.20(d)(2)(C) provides that the Commission shall establish a methodology to determine the market price of electricity in consideration of, among other things, the value of different electricity products, including baseload, peaking, and as-available electricity.

market. As the Re-MAT pricing mechanism adjusts to market conditions, it is probable that the prices for each product type will differ. The result is that bioenergy projects, for example, could receive prices that are different than those available to solar projects that may seek a contract from a different product type.

Accordingly, based on the current statutory language, we do not adopt a technology specific set aside for the portion of the 750 MW allocated to the IOUs under this program. We do, however, seek to promote these technologies within the guidelines of the statute.

### 12.5. Future Adjustments in Allocation of 750 MW Cap

We decline to adopt a mechanism for future adjustments in the capacity allocation of the 750 MW adopted in today's decision. Some parties recommend that the Commission adopt a methodology for periodic updates to the allocation methodology to account for, among other things, changes in a regulated utility's share of statewide peak demand. These parties state that more accurate allocation will be achieved in this manner. In D.07-07-027, the Commission did not elect to adopt a methodology for periodic updates of the allocation methodology on the basis that the costs devoted to regular updates would likely exceed benefits. We continue to find merit in the cost-benefit assessment set forth in D.07-07-027. For these reasons, we do not adopt a mechanism for future adjustments in capacity allocation.

## 13. Separate Tariffs for Public Water or Wastewater and other Program Participants Eliminated

This decision directs PG&E, SCE, and SDG&E to combine existing tariffs setting forth their § 399.20 FiT Program into a single tariff for each utility.

The § 399.20 FiT Program, as originally enacted by AB 1969, was limited to "electric generation facilities," as defined therein, owned and operated by a public water or wastewater agency. In D.07-07-027 and D.08-09-033, the Commission applied the "owned and operated" requirement to include other generators, beyond public water or wastewater agencies and directed regulated utilities to maintain two sets of tariffs on file with the Commission under § 399.20: one set of tariffs for generation owned and operated by public water or wastewater agencies and a second set of tariffs for generation owned and operated by other types of renewable generators. As a result of this directive in D.07-07-027 and D.08-09-033, the three largest regulated electric utilities currently have two § 399.20 FiT Program rate schedules on file with the Commission.

Now is the appropriate time to consolidate these tariff schedules. SB 380 amended § 399.20(b) by removing the requirement that electric generation facilities be owned and operated by a public water or wastewater agency. Subsequent amendments to § 399.20(b), including SB 32 and SB 2 1X retain the following language: "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:…"[75]

Overall, parties support the recommendation to consolidate tariff schedules. Consolidation of tariffs will decrease transaction costs by simplifying the administration of the program. In addition, based on the removal of the language in § 399.20 restricting the program to public water or wastewater agencies, we find no legal reason exists to maintain two separate tariff schedules

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[75] Additional criteria are omitted and are not relevant for purposes of this discussion.

and find it reasonable to direct PG&E, SCE, and SDG&E to consolidate the two schedules. Any related conforming changes to the § 399.20 FiT Program contracts must also be implemented. This direction to consolidate tariffs does not apply to the small utilities because we have directed them in Section 11 of this decision to withdraw their tariffs related to § 399.20.

Accordingly, PG&E, SCE and SDG&E shall modify tariff and contract provisions to reflect the consolidation of tariffs applicable to public water or wastewater agencies and tariffs for other customers into the § 399.20 FiT Program. These modifications shall be incorporated into the standard form contract and/or tariff that is being developed in this proceeding in accordance with the schedule set forth in the January 10, 2012 ALJ ruling. The Commission will review these provisions submitted by the utilities and, in a separate decision accept, reject, or modify the provisions. Related FiT tariff modifications will also be addressed in this separate decision.

## 14. Retail Customer Requirement Eliminated

This decision implements SB 32 by eliminating the requirement that participating generators be retail customers to participate in the § 399.20 FiT Program.

As originally enacted by AB 1969, § 399.20(b) required electric generation facilities to be, among other things, owned and operated by public water or wastewater agencies and a "retail customer" of an electrical corporation. SB 32 replaced the phrase "retail customer" with "located within the service territory of, and developed to sell electricity to …"[76] SB 32 also changed § 399.20 by eliminating the requirement that the facilities be owned and operated by public water or wastewater agencies. We address this change elsewhere in this decision. Now we focus on the replacement of the phrase "retail customer." SB 2 1X retains the modifications made by SB 32.

As a result of the SB 32 amendments, we now find that, according to the clear language of § 399.20, the program is not limited to retail customers of the electrical corporation and, instead, available to those that are owners or operators of the electric generation facility. The majority of parties support implementation of SB 32 under this interpretation. Silverado Power points out that eliminating the retail customer requirements will expand the options under the § 399.20 FiT Program to include, for example, locations in so-called brown fields with no existing load or customer. Similarly, FuelCell Energy points out that, in the absence of the retail customer requirement, an otherwise eligible biogas generator could be sited at an abandoned landfill or dairy digester that is not an existing retail customer of the purchasing utility. DRA also points to expanded opportunities for the program. We agree that expanded possibilities exist and do not attempt to identify them all here.

Some parties request additional clarifications of the statute based on the elimination of the "retail customer" requirement. SunEdison and Joint Solar Parties request further clarification on whether third-parties can participate in the § 399.20 FiT Program. We clarify that generating systems owned and

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[76] § 399.20(f).

operated by third-parties (and not the retail customer of record) are eligible to participate in the § 399.20 FiT Program.

We disagree, however, with SunEdison's and Joint Solar's interpretation of statutory language to mean that SB 32 prohibits the sale of excess generation. SunEdison and Joint Solar Parties claim that the phrase in § 399.20(b) "developed to sell electricity to, an electrical corporation" together with the recent elimination of the "retail customer" requirement, means that the Legislature only intended "full" sales (not excess sales) under the § 399.20 FiT Program. However, that statute is silent on these types of sales. If the Legislature intended to limit excess sales it could have done so. Therefore, because the plain statutory language does not prohibit excess sales, we reject the interpretation proposed by SunEdison and Joint Solar.

As a result, PG&E, SCE, and SDG&E are required to offer generators two options: either full sales or excess sales. The nameplate capacity, however, of all generators participating in this program is limited to 3 MW, regardless of the sales option.

Accordingly, PG&E, SCE, and SDG&E shall remove, as necessary, references to retail customers in the FiT Program standard form contract and/or tariff that is being developed in this proceeding in accordance with the schedule set forth in the January 10, 2012 ALJ ruling. The Commission will review this provision submitted by the utilities and, in a separate decision accept, reject, or modify the provision. Related FiT tariff modifications will also be addressed in this separate decision.

## 15. Inspection and Maintenance Report – Annual Requirement Adopted

This decision implements SB 32 by adding an inspection and maintenance provision to the tariffs and the power purchase agreements under the § 399.20 FiT Program.

SB 32 amends § 399.20 by adding an inspection and maintenance provision at subsection (p) of § 399.20. Section 399.20(p) provides that the "owner of the 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." SB 2 1X makes no changes to this provision. Section 399.20(p) further provides that this inspection and maintenance report be prepared by a California-licensed electrician who is not the owner or operator of the facility and that the report must be prepared at the expense of the owner or operator.

All parties agree that § 399.20(p) requires an inspection and maintenance report by a California-licensed electrician who is not the owner or operator of the facility. We find this interpretation of the statute consistent with the plain language of the statute and, therefore, reasonable.

Parties disagree on some of the implementation details of § 399.20(p), such as the appropriate time interval between reports. PG&E, SCE, and SDG&E propose annual reporting, which they argue is consistent with the plain statutory language. AECA, CALSEIA, and FuelCell Energy propose reporting once every two years (biennially) rather than annually because annual reporting would be duplicative, burdensome, and costly.

The language of the statute does not provide definitive direction on this question. However, we find annual reporting, rather than a longer time interval, reasonable based on the importance of proper maintenance of the electric system.

Joint Solar Parties and SunEdison suggest that, to avoid unnecessary duplication, the Commission coordinate the § 399.20(p) report with any required reports required under the Tariff Rule 21. We acknowledge that possible efficiencies may exist in such coordination. However, because the Commission is currently engaging in efforts to revise Tariff Rule 21 in R.11-09-011, we find it more appropriate to attempt to coordinate the reporting requirements after the Rule 21 revision is complete. Therefore, parties should bring any required coordination issues to our attention in either R.11-09-011 or in this proceeding at that time.

We do not at this time accept the recommendation of some parties, such as PG&E and the Californians for Renewable Energy (CARE), that we adopt a standardized form for this report. While efficiencies might be gained, we find the particularities of safety and reliability matters are better left to the individual utilities but we support the utilities' own efforts to coordinate on this issue and create a standardized form.

FuelCell Energy recommends the confidential treatment of these reports but provides no specific basis for its request. No other parties commented on this issue. Accordingly, in the absence of a showing that the confidential treatment is needed to protect a specific aspect of the market or the report, we deny this request.

As recommended by the utilities, we find that language concerning inspection and maintenance reporting should be included in both the FiT Program standard form contracts and tariff.

Accordingly, PG&E, SCE, and SDG&E shall add a provision reflecting the inspection and maintenance reporting to the FiT Program standard form contract and/or tariff that is being developed in this proceeding in accordance with the schedule set forth in the January 10, 2012 ALJ ruling. The Commission will review this provision submitted by the utilities and, in a separate decision accept, reject, or modify the provision. Related FiT tariff modifications will also be addressed in this separate decision.

## 16. 10-day Reporting Requirement of Request for Service Under Tariff

This decision implements SB 32 by directing utilities to add a 10-day reporting requirement to their tariffs under the § 399.20 FiT Program. The information required is set forth in Attachment A.

SB 32 amends § 399.20 by adding subsection (m). Subsection (m) directs utilities to report, within a 10-day period, the receipt of a request by a generator for service under tariffs filed pursuant to the § 399.20 FiT Program. Subsection (m) provides that, within 10 days of receipt of a request for a tariff pursuant to this section, the electrical corporation that receives the request shall post (1) a copy of the request on its Internet Web site and (2) the name of the city where generation facility is located. Subsection (m) also states that information in the request that is proprietary and confidential, including, but not limited to, address information beyond the name of the city shall be redacted. SB 2 1X makes no changes to this provision.

PG&E, Solar Alliance and Vote Solar Initiative, Sustainable Conservation, and GPI, among others, support increased transparency in the process to obtain service under the § 399.20 FiT Program and, for that reason, support the public disclosure of certain information. However, as a preliminary matter, these parties request clarification from the Commission on when the 10-day reporting period begins.

The statutory language provides that this reporting period begins within 10 days of receipt of a request for a tariff. PG&E suggests that the language means that the 10-day period start when the contract is signed by both the seller and the utility. SCE supports the same interpretation because no need for public posting of information would occur, according to SCE, if a seller requested but did not ultimately enter into a power purchase agreement due to eligibility issues or other conflicts. The majority of parties provide no comments on this topic.

We agree that the pertinent language is unclear as it applies to the existing process within the § 399.20 FiT Program. Secondary legal sources, such as the legislative history, do not provide clarification. We also agree with parties that, in implementing subsection (m), the goal should be increased transparency of the program to facilitate participation by generators. To achieve this goal, we implement subsection (m) in a manner that requires the reporting of information within 10 days of both (1) signature of a power purchase agreement by the seller (generally referred to as the "execution date") and (2) signature by both the seller and the utility (generally referred to as the "effective date").[77] We find that information pertaining to both dates is critical to providing increased transparency regarding the program. We disagree with SCE that information pertaining to contracts signed by seller but never obtaining an effective date (by obtaining signatures by both seller and utility) is not useful information. As a

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[77] D.11-11-012 (*Decision Granting, with Modifications, the Motion by Clean Coalition for Immediate Amendments of the Southern California Edison Company AB 1969 CREST Power Purchase Agreement*) at 30.

minimum, each utility should state on its website the number of proposed contracts and the reasons for rejection.

Regarding the type of information to be disclosed within 10 days, DRA recommends the Commission adopt a reporting requirement for the § 399.20 FiT Program similar to the reporting systems already in place by PG&E and SDG&E for Project Development Status Reports. DRA does not recommend relying on SCE's current reporting system and claims it does not provide a sufficient model. The Solar Alliance and the Vote Solar Initiative identify a list of topics to be identified in the internet posting, including the city location, project name, developer name, project status, expected commercial operation date, original bid, installed capacity and other information be posted on the internet. Solar Alliance and Vote Solar Initiative point out that this information is largely consistent with the information required by the Commission in D.10-12-048 (RAM Program) and implemented by PG&E in Advice Letter 3809-E for tracking and reporting of RAM projects. CALSEIA states that PG&E and SCE currently comply with this provision by providing the information set forth in their AB 1969 programs. SunEdison supports the position of Solar Alliance and Vote Solar Initiative to create a reporting requirement consistent with other Commission programs. SunEdison sees value in making this information publicly available so as to allow participants the ability to assess their potential participation in the program but also urges the Commission avoid duplication with Rule 21 reporting requirements. PG&E also recommended that the substance of the posting be standardized and specifically suggests that city location, capacity, expected deliveries, length of contract and other information be included. SCE recommends a list of topics similar to Solar Alliance and Vote Solar Initiative.

Silverado Power suggests confidentiality may be furthered protected by release of the county rather than the city.

We find that applying the reporting requirement to topics already included in existing programs, such as the RAM Program implemented by D.10-12-048 and various advice letters, including PG&E's Advice Letter 3809-E, is reasonable because these existing reporting requirements provide efficiencies and transparency. While the statutory language does not require this level of information, it does not prohibit the Commission from requiring such disclosure and is justified by our goal of increased transparency.

The required information is set forth below. We adopt a standardized form to be used by all utilities to post the relevant information. Standardization of the form will likely reduce transaction costs and simplify access to the information on the Internet. To avoid unnecessary duplication of the reporting requirement, we will revisit this matter if duplication with Tariff Rule 21 reporting requirements is brought to our attention in R.11-09-011.

The form to be used by all electric corporations to post information on the internet is included herein at Attachment A.[78]

Accordingly, PG&E, SCE, and SDG&E shall add a provision reflecting the 10-day reporting requirement for requests for service in the FiT Program

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[78] The form includes seller name, project name, status (on schedule, delayed, operation, terminated), capacity alternating current (MW), expected energy production (gigawatt hours/yr) technology, contract price ($/MWh), vintage (existing, restart, repower, new), contract term (years), location (city, county), contract execution date, contractual online date, actual online date, 6-month extension granted (yes or no), date of termination and reason why terminated.

standard form contract and/or tariff being developed in this proceeding in accordance with the schedule set forth in the January 10, 2012 ALJ ruling. The Commission will review this provision submitted by the utilities and, in a separate decision accept, reject, or modify the provision. Related FiT Tariff modifications will also be addressed in this separate decision.

## 17. Publicly-Owned Electric Utilities – Separate Program

This decision does not adopt any feed-in tariff program requirements for publicly owned electric utilities.

SB 32 added § 387.6 to the Pub. Util. Code. Section 387.6 requires, generally, that a local publicly owned electric utility offer a tariff to owners or operators of electric generation facilities within its service territory. Parties provided comments on this issue and on the issue of whether certain issues set forth in SB 32 and SB 2 1X may benefit from coordination with local publicly owned electric utilities, such as, the calculation of proportionate share of the 750 MW program cap.

In response, the California Municipal Utilities Association (CMUA) states that the Commission has no jurisdiction over publicly owned electric utilities. CMUA further states that the Commission has no jurisdiction to calculate proportionate share of the 750 MW cap for publicly owned electric utilities and that § 387.6(e) makes clear that the Commission has no authority to determine that share. CMUA further states that no coordination is needed between the program adopted by the Commission for IOUs and the program adopted by municipalities for publicly owned electric utilities but acknowledges that feed-in tariff programs implemented by IOUs may provide informative examples for the governing boards of publicly owned electric utilities. Other parties provided no further comments.

We agree with the CMUA that based on § 387.6, the Commission has no authority to design or implement a feed-in tariff program for publicly owned electric utilities. We further agree that SB 32 increased the total § 399.20 FiT Program cap to 750 MW and allocates a portion of this 750 MW to publicly owned electric utilities. We direct PG&E, SCE, and SDG&E to work cooperatively with publicly owned utilities as needed to share information that will assist them in developing a feed-in tariff program consistent with § 387.6. As discussed above, we assert jurisdiction over IOUs and the allocation methodology relied upon to determine their share of program capacity.

## 18. Utility Discretion to Deny Tariff Request Under § 399.20

This decision implements SB 32 by directing utilities to incorporate a provision into their standard form contracts, which utilities and parties are currently developing, for written notice of a denial of a request for service under the § 399.20 FiT Program.

SB 32 adds subsection (n) to § 399.20 to provide the electric corporation with the ability to deny a tariff request by an electric generation facility in certain circumstances relating, generally, to compliance with the statute and ensuring the safety of the electric grid.

In its March 2011 opening brief, FuelCell Energy suggested that the Commission clarify this provision to avoid unnecessary misunderstandings and disputes. Specifically, FuelCell Energy requested that the Commission determine the point in the contracting process that a utility may deny such a tariff request. Other parties, including the Solar Alliance and the Vote Solar

Initiative support further clarification but fail to provide a specific proposal with supporting rationale. These parties note the importance of clarifying the term "inadequate" interconnection point but others recognize the difficulty in establishing greater certainty.

SCE suggests that an affidavit may be sufficient means to determine compliance with subsection (n)(3). Silverado Power suggests that, in the interest of contract certainty and securing financing, that contract termination provisions only apply before a contract is executed. SDG&E states, in addition to the need for more specificity, that the language of subsection (n) would also permit a denial in other circumstances, such as a when the facility is located outside of the service territory as set forth in subsection (f).

In the interest of administrative ease and reducing transaction costs, it is important to adopt clear policies around when an electric corporation may deny a tariff request. We find that it is also reasonable to place a certain amount of discretion in the utility to carrying out subsection (n), especially since the denials are subject to a statutorily required appeal process before the Commission under § 399.20(o).[79] Neither the statutory language itself nor secondary sources further clarify this matter. At a minimum, we find that any denial of service under § 399.20(n) must be provided in writing to the producer.

Accordingly, PG&E, SCE, and SDG&E shall add a provision regarding denial of service by the utility to the FiT Program standard form contract and/or

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[79] § 399.20(o) provides that "Upon receiving a notice of denial from an electrical corporation, the owner or operator of that electric generation facility denied a tariff pursuant to this section shall have the right to appeal that decision to the commission."

tariff that is being developed in this proceeding in accordance with the schedule set forth in the January 10, 2012 ALJ ruling. The Commission will review this provision submitted by the utilities and, in a separate decision accept, reject, or modify the provision. Related FiT tariff modifications will also be addressed in this separate decision.

## 19. Contract Termination Provisions

This decision implements SB 32 by directing utilities to incorporate a provision into their standard form contract and/or tariff, which utilities and parties are currently developing, for termination of service under the § 399.20 FiT Program.

SB 32 adds subsection (l) to § 399.20 to provide for contract termination before the contract expiration date in certain circumstances. SB 2 1X makes no modifications to this subsection. Subsection (l) of § 399.20 provides, generally, that the owner or operator of an electric generation facility shall continue to receive service under the tariff or contract until either of the following occurs (1) the owner or operator no longer meets the eligibility requirements for receiving service pursuant to the tariff or contract or (2) the period of service established by the Commission pursuant to subdivision (d) is complete.

Parties, such as Silverado Power, SunEdison, and Sustainable Conservation, point out that the termination provision should be narrowly interpreted and not increase the level of uncertainty by subjecting a contract to unknown or subsequently imposed eligibility requirements. SCE suggests that the language of the statute be incorporated into the tariffs and form contracts together with several other provisions. FuelCell Energy agrees with Silverado Power, SunEdison, and Sustainable Conservation that the termination provisions should be interpreted narrowly and also suggests that the Commission adopt a process for administering termination matters, pointing to the procedure established by the CEC under AB 1613. Under AB 1613, the CEC certifies eligibility of all facilities in the first instance and administers a decertification process in the event a facility falls out of compliance. Alternatively, FuelCell Energy suggests that the contract could provide for a notice provision from the defaulting party and a dispute resolution process, such as arbitration. FuelCell Energy also asks for clarification on whether a termination results in returning the capacity back into the § 399.20 FiT Program. SCE requests the Commission clarify whether terminated capacity must be replaced by additional contracts under the § 399.20 Program or replaced with capacity in another RPS program.

Consistent with the plain language of § 399.20(l) and in the interest of promoting stability of this program, it is reasonable to interpret the statute as requiring termination of the two events described in subsection (l)(1) and (l)(2) to be included in the standard form contract and/or tariff but that the Commission will not exclude other termination rights currently being considered in this proceeding considering the joint standard form contract.[80] Regarding questions raised by parties about the need for a decertification program similar to the program under AB 1613 administered by the CEC, we find no need for such a

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[80] § 399.20(l) provides as follows: "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 occur: (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."

program now. To the extent parties find that an alternative resolution process, such as that suggested by FuelCell Energy, might be appropriate, we direct parties to pursue this matter in the ongoing discussion concerning a single form contract for the program described in the January 10, 2012 ALJ ruling.

Accordingly, PG&E, SCE, and SDG&E shall add a provision reflecting contract termination to the FiT Program standard form contract and/or tariff that is being developed in this proceeding in accordance with the schedule set forth in the January 10, 2012 ALJ ruling. The Commission will review this provision submitted by the utilities and, in a separate decision accept, reject, or modify the provision. Related FiT tariff modifications will also be addressed in this separate decision.

## 20. Expedited Interconnection Procedures

This decision acknowledges that expedited interconnection is critical to the success of the § 399.20 FiT Program and implements the directives set forth in SB 32 pertaining to expedited interconnection by clarifying that parties should rely on the existing provisions of Tariff Rule 21 until the Commission finalizes its ongoing efforts to refine Rule 21 and expedited interconnection in R.11-09-011. In addition, we find that, until the Commission makes a final determination in R.11-09-011, utilities shall allow generators to choose which interconnection processes to use, either the process set forth in the existing Tariff Rule 21 or the FERC interconnection procedures under the Wholesale Distribution Access Tariff (referred to as "WDAT").[81] We anticipate that generators will find Rule 21, as revised in R.11-09-011, sufficient to meet the statutory mandate of expedited interconnection and, at that point, we will no longer permit interconnection under the federal tariffs. On a broad level, we briefly summarize the issues pertaining to expedited interconnection below as more specific consideration of the issues will occur in R.11-09-011.

SB 32 added subsection (e) to § 399.20 to provide that an electric corporation shall provide expedited interconnection procedures for a facility that is connected on a distribution circuit and generates electricity in a manner to offset peak demand on the electric circuit. Notably, in D.07-07-027, the Commission established a need for expedited interconnection under AB 1969 "to prevent interconnection from becoming a barrier to completion, …" and required the utilities to follow the interconnection procedures in Rule 21 or FERC interconnection procedures.[82] Parties provided comments on this topic.

In March 2011 briefs, PG&E and SCE suggest that the Commission may not be able to address this issue because connections on the distribution level are FERC-jurisdictional. PG&E further suggests that an expedited procedure for only the § 399.20 FiT Program is not appropriate because interconnection to the grid must include a comprehensive review, and also states that it will make reasonable efforts to accommodate interconnection consistent with its legal

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[81] The utilities use different names for their FERC-jurisdictional interconnection tariffs. SCE and SDG&E each use WDAT, while PG&E uses "Wholesale Distribution Tariff." This decision uses the term WDAT to refer to each utility's tariff.

[82] D.07-07-027 at 40.

obligations. SCE points to WDAT as a possible alternative process. We agree with PG&E that interconnection must be addressed on a comprehensive level and, therefore, anticipate addressing these issues in R.11-09-011.

Furthermore, to the extent generators decided to rely on the Tariff Rule 21, the existing provisions of Tariff Rule 21 will apply, rather than any potential revised version of Rule 21, until the Commission issues a decision on potential revisions to the Rule 21 Tariff in R.11-09-011 unless a different direction is provided for in either this proceeding or in R.11-09-011 by ruling of the Administrative Law Judge or Commission decision.

IREC, the Solar Alliance, and the Vote Solar Initiative find Rule 21, in its current format, insufficient but suggest other possible models. IREC also urges the Commission to pursue consistency among the many existing interconnection procedures. FuelCell Energy suggests current efforts underway before the CAISO regarding the Generator Interconnection Procedures and the electric utilities' efforts to reform qualifying facilities' interconnection procedures are sufficient to address the needs under the § 399.20 FiT Program. CALSEIA recommends that the Commission monitor the electric utilities' continued progress to reform the WDAT and suggests that these reforms may be sufficient for purposes of the § 399.20 FiT Program. The Solar Alliance and the Vote Solar Initiative support reliance on the WDAT as the most viable existing option. Sustainable Conservation points out that interconnection sometimes takes a year or longer and recommends reliance on Rule 21 as an accessible means of addressing interconnection under the Commission's jurisdiction.

As stated above, we acknowledge that expedited interconnection is critical to the success of the § 399.20 FiT Program. These issues are scheduled to be addressed in R.11-09-011. However, until the Commission makes a final determination in R.11-09-011 revisions to Tariff Rule 21 that may provide a more expedited interconnection process to participants in this Program, utilities shall allow generators to choose which interconnection processes to use, either the process set forth in the Rule 21 Tariff or the WDAT. We direct this choice since the utilities follow different internal processes regarding which interconnection procedure is allowed for different renewable energy programs. By allowing generators to choose the process, generators will be able to evaluate which interconnection procedure better addresses their specific needs.

## 21. Refunds of Other Incentives – California Solar Initiative and Small Generator Incentive Program

SB 32 added subsection (k) to § 399.20 to require owners of eligible generation facilities to refund any incentives received from the California Solar Initiative (CSI) or the Small Generator Incentive Program (SGIP) before participating in the FiT Program. SB 2 1X made no changes to subsection (k). Parties commented on implementation of this provision.

Most parties agreed that refund of any incentives was appropriate prior to participating in this program but presented different proposals on how to implement and calculate such refunds. The calculation of an appropriate refund is sufficiently complicated and case specific that we find a reasonable approach is to adopt PG&E's proposal articulated in its November 2011comments.

Specifically, PG&E suggests that customers who participate in the CSI or SGIP be required to provide the benefits of their distributed generation installation for a period of ten years and that these customers be held to that commitment, for which they have been compensated. PG&E further suggests that instead of establishing an incentive refund structure, participants in the CSI or SGIP be ineligible for the § 399.20 FiT Program for 10 years from the date they first received the incentive. Upon completion of the 10-year commitment, if they are otherwise eligible, CSI and SGIP facilities can then participate in the § 399.20 FiT Program. Likewise, PG&E suggests that net-energy metering customers be ineligible for the § 399.20 FiT Program. Net-energy metering customers that prefer the FiT price for exports must first terminate their participation in net-energy metering.

We adopt PG&E's proposal. A generator that previously received incentives under CSI or SGIP can participate in the § 399.20 FiT Program and will owe no refund if it has been online and operational for at least ten years from the date it first received the incentive. Net-energy metering customers can participate in the § 399.20 FiT Program but must first terminate participation in net-energy metering.

Accordingly, PG&E, SCE, and SDG&E shall add a provision reflecting the eligibility to participate in the § 399.20 Fit Program based on past participation and receipt of CSI and SGIP incentives in the FiT Program standard form contract and/or tariff that is being developed in this proceeding in accordance with the schedule set forth in the January 10, 2012 ALJ ruling. The Commission will review this provision submitted by the utilities and, in a separate decision accept, reject, or modify the provision. Related FiT tariff modifications will also be addressed in this separate decision.

## 22. FERC Certification of Generator for Qualifying Facility (QF) Status

Since this program is developed to be compliant with PURPA, a participating generator must register with FERC as a QF.[83] Generators may utilize FERC's self-certification[84] process by filling out FERC's Form 556. Generators can visit FERC's website for more information on how to self-certify as a qualifying facility.[85]

## 23. Transition Issues

Parties raised the issue of whether rules under the existing AB 1969 program apply to projects now in the queue or whether the rules adopted today apply.

Silverado raised this issue and points out that it has projects currently on the wait lists for the § 399.20 FiT Program under SCE's CREST program.[86] As a result, it is unclear, from its perspective, which rules will apply to those projects. The October 13, 2011 Staff Proposal recognized this issue and acknowledges that the transition to the new rules presents complications for some generators,

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[83] The fundamental premise of the pricing proposal adopted today is that the prices reflect avoided costs, which the Commission has authority to set under the PURPA for QFs. In the absence of such federal authority, the Commission would not have jurisdiction to establish the wholesale FiT Program prices. Therefore, to satisfy the PURPA requirements, the participating generator must be a QF. (PG&E April 16, 2012 Reply Comments.)

[84] FERC provides two certification options: self-certification or FERC certification.

[85] How to obtain QF Status: http://www.ferc.gov/industries/electric/gen-info/qual-fac/obtain.asp.

especially those operating under SCE's FiT Program.[87] The Staff Proposal also notes that SB 32 became effective on January 1, 2010 and, as a result, at that time generators were placed on notice that the rules of the FiT Program would change.

We agree that generators had ample notice that the rules would change. We also note that the Commission's general policy is to apply the rules in place at the time the contract is executed. No contracts exist for those projects identified by Silverado in the queue. Therefore, we find that projects in the queue and without a contract must comply with the new rules adopted today.

## 24. Motion for Further Consideration of an "Administratively Determined, Avoided Cost Based Pricing Mechanism" - Denied

The Joint Parties filed a motion[88] on December 19, 2011 and noted their concern that the Commission or ALJ had given the Renewable FiT Staff Proposal greater consideration or more evidentiary weight than other pricing proposals because the Staff's Proposal was presented in an ALJ's ruling dated October 13, 2011 and, in addition, was discussed at a Staff Workshop on September 26, 2011.

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[86] Silverado April 9, 2011 comments to proposed decision at 4, citing to Silverado June 27, 2011 reply comments.

[87] October 13, 2011 Staff Proposal at 19.

[88] *Joint Motion of the Center for Energy Efficiency and Renewable Technologies; AG Power Group, LLC; Sustainable Conservation; Agricultural Energy Consumers Association; Green Power Institute; California Wastewater Climate Change Group; California Farm Bureau Federation; Fuel Cell Energy; and FlexEnergy, Inc., for a Ruling Directing the Consideration of an Administratively determined Avoided Cost Pricing Methodology for the Renewable FIT at a January 2012 Workshop that Would be Part of the Record for the Decision on the Renewable FIT* filed December 19, 2011.

These concerns were presented in a motion seeking further consideration in a workshop on the record of an "administratively determined, avoided-cost based pricing mechanism."[89] The motion stated that further consideration of such a pricing mechanism was needed because the ALJ's October 13, 2011 ruling, in combination with the Renewable FiT Staff Proposal, effectively demonstrated to the Joint Parties that the Staff Proposal would, in some form, prevail before the Commission.

We emphasize that the Renewable FiT Staff Proposal was one of many pricing proposals considered by the Commission in this proceeding. The Joint Parties' suggestion that the record was unduly limited by the Commission's consideration of the Renewable FiT Staff Proposal is misplaced. The Commission gave full consideration to all pricing options presented in the proceeding, including that of an "administratively determined, avoided-cost based pricing mechanism."

Moreover, we emphasize that all parties had ample opportunities to present their pricing proposal to the Commission. Pricing proposals were requested in early and late March 2011 and, again, in July and August 2011. In November 2011, we sought input on pricing issues from parties. While the November 2011 comments focused on the Renewable FiT Staff Proposal, we sought input on a broad basis seeking to understand the pros and cons of the Staff Proposal as compared to various alternative-pricing proposals.

The motion is denied.

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[89] *Id*. at 5.

## 25. Petition for Modification of Decision 07-07-027 by Solutions for Utilities, Inc. - Denied

On June 18, 2010, Solutions for Utilities Inc. (Solutions for Utilities) filed a petition for modification of D.07-07-027.[90] Solutions for Utilities seeks specific changes to the mechanics of the § 399.20 FiT Program as administered by SCE and as authorized in D.07-07-027. Specifically, Solutions for Utilities asks the Commission to modify SCE's standard power purchase agreement used for the § 399.20 FiT Program in various ways, including: adding curtailment provisions; deleting paragraphs 4.2, 14.2, 14.4; and striking the Interconnection Facilities and Financing Ownership Agreement (IFFOA) and the IFFOA's attachments from the power purchase agreement. Finally, Solutions for Utilities asks the Commission to remove the MPR in SCE's power purchase agreement and to change the pricing mechanism under the § 399.20 FiT Program.

PG&E, SCE, and SDG&E responded in opposition to the petition for modification. The utilities asked the Commission to deny the petition based on the timing of the filing, since the petition was filed more than one year after the issuance of D.07-07-027. The utilities also opposed the substance of the petition.

Many of the issues framed by Solutions for Utilities' petition for modification already have been addressed in different aspects of this proceeding. The remaining issues will be addressed either in this proceeding or in the separate, ongoing Commission rulemaking on Rule 21 interconnection matters, R.11-09-011.

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[90] This petition for modification was filed in R.06-05-027. This proceeding is the successor proceeding to R.08-08-009 and R.06-05-027.

In this proceeding, on November 10, 2011, the Commission issued a decision granting, in part, a motion filed by the Clean Coalition to change SCE's § 399.20 FiT Program standard power purchase agreement in a manner similar to those sought by Solutions for Utilities' petition for modification.[91] For instance, the November 10, 2011 decision addressed a request to add curtailment provisions and delete paragraphs 4.2, 14.2, 14.4. In addition, today's decision addresses the issue of pricing under the § 399.20 FiT Program which is also framed by Solutions for Utilities' petition for modification. A future decision in R.11-05-005 will address standard terms and conditions for the § 399.20 FiT Program standard power purchase agreement. Finally, R.11-09-011 is the proper forum to address modifications to the IFFOA and other interconnection agreement issues.

Therefore, because all issues framed by Solutions for Utilities' petition for modification either have been addressed or are scheduled to be addressed in either this proceeding or in R.11-09-011, the petition is denied.

## 26. Petition for Modification of Decision 07-07-027 by Sustainable Conservation - Denied

On June 29, 2011, Sustainable Conservation filed a petition for modification of D.07-07-027. Sustainable Conservation's petition requests that the Commission do as follows: (1) direct the utilities to use the Tariff Rule 21 for customers that interconnect to the distribution system; (2) assert jurisdiction over

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[91] *See* D.11-11-012 (*Decision Granting, with Modifications, the Motion by Clean Coalition for Immediate Amendments of the Southern California Edison Company AB 1969 CREST Power Purchase Agreement*)

the distribution-level power lines of California's electric utilities; and (3) modify D.07-07-027 to strike language giving utilities the discretion to require either Tariff Rule 21 or FERC interconnection procedures.

SCE and PG&E responded in opposition to the petition for modification due to the timing of the filing, since the petition was filed more than a year after D.07-07-027. SCE and PG&E also opposed the substance of the petition. IREC and Independent Energy Producers supported the petition's request that the Commission address the general interconnection issues raised in the petition.

The issues framed by Sustainable Conservation's petition for modification are addressed in today's decision or will be addressed in the separate, ongoing rulemaking before the Commission, R.11-09-011. We expect that the first two issues raised by the petition will be addressed, to the extent necessary, in R.11-09-011. Today's decision addresses the third issue raised in the petition. Specifically, today's decision directs the utilities to give generators a choice of which interconnection procedures to use, either the Tariff Rule 21 or the FERC interconnection tariffs.

Therefore, because the issues framed by Sustainable Conservation's petition for modification are addressed in today's decision or will be addressed in R.11-09-011, the petition is denied.

## 27. Comments on Proposed Decision

The proposed decision of ALJ DeAngelis in this matter was mailed to the parties in accordance with § 311 of the Pub. Util. Code and comments were allowed under Rule 14.3 of the Commission's Rules of Practice and Procedure. Comments were filed on April 9, 2012, and reply comments were filed on April 16, 2012. To the extent required, revisions have been incorporated to reflect the substance of these comments.

## 28. Assignment of Proceeding

Mark J. Ferron is the assigned Commissioner and Regina DeAngelis is the assigned ALJ in this proceeding.

## Findings of Fact

1. The June 27, 2011 ALJ Ruling, our RAM Program, and the October 13, 2011 Renewable FiT Staff Proposal contain the following five policy guidelines relevant to today's decision:

    i. Establish a feed-in tariff price based on quantifiable ratepayer avoided costs that will stimulate market demand;

    ii. Contain costs and ensure maximum value to the ratepayer and the utility;

    iii. Ensure administrative ease and lower transaction costs for the buyer, seller, and regulator;

    iv. Use existing transmission and distribution infrastructure efficiently; and

    v. Establish project viability criteria to increase probability of successful projects within the program.

2. The MPR price may be too high or too low for different FiT product types, such as baseload, peaking as-available and non-peaking as-available.

3. The MPR is a price based on the costs of a natural gas-fired electric plant, and not a renewable generator. The MPR reflects the costs of fossil fuels.

4. The renewable market has evolved since the Commission first established the MPR in 2003 at the beginning of the RPS Program.

5. The renewable market is sufficiently robust to serve as the point of reference for establishing the market price for small renewable projects rather than the MPR, which reflects the costs of a combined-cycle natural-gas power plant.

6. The methodologies presented to determine certain adders, such as those based on technology specific generation, are largely based on general avoided societal costs, and not utility costs.

7. It is not easy to quantify the general societal benefits that support specific types of renewable technologies consistent with the provisions of state law and federal law.

8. Net surplus generation is provided without a power purchase agreement on an intermittent, unpredictable, and as-available basis over a 12-month period. In addition, the Commission found that the only generation the utility avoids when a net-energy metered customer provides surplus generation is reduced electricity procurement from the short-term wholesale market.

9. This decision adopts a pricing methodology that relies upon the November 2011 renewable market power pricing information from the RAM adopted in D.10-12-048 and takes components from a number of different pricing proposals presented by parties, including IREC, SunEdison, Silverado Power, Vote Solar Initiative, and SCE and by Staff. The pricing methodology also relies upon a two-month price adjustment mechanism to increase or decrease the FiT price for a particular product type based on market conditions.

10. A separate price for each of the three product types (baseload, peaking as-available, and non-peaking as-available) better captures the value provided by the different technology types.

11. Baseload projects provide firm energy deliveries (e.g., bioenergy and geothermal); peaking projects provide non-firm energy deliveries during peak hours (e.g., solar); and non-peaking as-available projects provide non-firm energy deliveries during non-peak hours (e.g., wind and hydro).

12. There is not enough market information for the three product types to enable us to adopt a unique starting price for each product type.

13. Adjusting the starting price by time-of-delivery factors based on the generator's actual energy delivery profile captures the value of each generator to the utility.

14. Based on the results from the November 2011 RAM auction, we anticipate that the starting price for each separate product type will be $89.23/MWh (pre-time-of-delivery adjustment).

15. The Re-MAT price should increase or decrease based on market interest in a product type, which may be determined by how many projects execute contracts at a particular Re-MAT price.

16. Ratepayer exposure to excessive cost due to market manipulation or malfunction is possible.

17. Temporarily suspending the program based on evidence of market manipulation or malfunction will guard against ratepayer exposure to excessive costs.

18. Allocating a utility's total capacity share to the three product types over a limited time period will serve to stimulate the market for small renewable distributed generation by providing an adequate supply of available capacity to each product type.

19. The total process for a deliverability study, which can take two years, may require costly upgrades to the transmission system in order to make the generator fully deliverable. The CAISO is currently conducting a stakeholder process to evaluate alternative paths to deliverability for distributed generation.

20. To ensure ratepayer indifference under § 399.20(d)(4), a market-based approach to pricing is in the best interest of California electricity customers.

21. There is no statutory provision requiring the adoption of pricing on a technology-specific basis.

22. A market-based price accounts for all of a generator's costs, including environmental compliance costs.

23. The location and transmission adders proposed during the proceeding do not represent actual costs that would be avoided by the utilities.

24. This decision implements the statutory amendments by increasing the maximum size of the eligible facility to 3 MW.

25. Additional measures must be implemented to prevent daisy-chaining, i.e., when a project appears to be part of a larger overall installation by the same company or consortium in the same general location, as daisy-chaining is a means to evade the size restrictions.

26. Unless today's decision modifies the RAM Program, the RAM Program and the FiT Program will overlap for projects 3 MW and under and the potential for gaming of the price of the two programs for projects of 3 MW and under will exist.

27. A means to ensure that only viable projects participate in the FiT Program is required.

28. Increasing the viability of contracts executed pursuant to the FiT Program will allow for more efficient management of the limited program capacity and benefit the market by reducing speculative contracts.

29. Supporting viable projects supports the fifth policy guideline adopted by this decision to increase the probability of successful projects by establishing project viability criteria.

30. The plain language of the statute provides the Commission with authority to modify the program as applied to small electrical corporations in a manner

that includes fully removing these utilities from the program. The costs of administering this program for the smaller utilities outweighs any potential benefit from their contribution of approximately 3 MW to the overall program.

31. The plain language of the statute establishes a total cap of 750 MW for the entire § 399.20 Program.

32. Consistency and administrative simplicity will be furthered by retaining the existing allocation methodology for 750 MW, updated in certain respects, adopted by the Commission in D.07-07-027.

33. No statutory provision requires us to consider a set aside for a particular technology .

34. PG&E, SCE, and SDG&E maintain two tariff schedules under § 399.20 which are similar in many respects. In the interest of administrative efficiency, the two separate schedules should no longer be retained.

35. The plain language of § 399.20 establishes that the FiT Program is not limited to retail customers of the electrical corporation but, instead, available to those that are owners or operators of the electric generation facility.

36. The plain language of the statute does not prohibit the sale of excess generation.

37. While the plain language of the statute does not provide definitive direction on the question of reporting frequency, annual reporting, rather than a longer time interval is appropriate because of the importance of proper maintenance of the electric system.

38. Adopting reporting requirements similar to those already included in existing programs, such as the RAM Program implemented by D.10-12-048 and various advice letters, including PG&E's Advice Letter 3809-E, provides efficiencies and transparency. While the statutory language does not require this

level of information, it does not prohibit the Commission from requiring such disclosure and is justified by our goal of increased transparency.

39. Administrative ease and reducing transaction costs are achieved by adopting clear policies around when an electric corporation may deny a tariff request; it is also reasonable to place a certain amount of discretion in the utility to carrying out subsection (n), especially since the denials are subject to a statutorily required appeal process before the Commission.

40. Neither the statutory language itself nor secondary sources further clarify denial of requests under § 399.20(n).

41. The statutory language set forth in § 399.20(l) and the interest of promoting stability of this program suggest that the termination provisions be interpreted narrowly.

42. Expedited interconnection is critical to the success of the § 399.20 FiT Program and is required by statute.

43. SB 32 added subsection (k) to § 399.20 to require owners of eligible generation facilities to refund any incentives received from the CSI or the SGIP before participating in the FiT Program.

44. The Joint Parties filed a motion on December 19, 2011 requesting further consideration of an administratively determined, avoided cost based pricing mechanism and noted their concern that this proceeding had given the Renewable FiT Staff Proposal greater consideration or more evidentiary weight than other pricing proposals because the Staff's Proposal was presented in an ALJ's ruling dated October 13, 2011 and, in addition, discussed at a Staff Workshop on September 26, 2011.

45. The issues framed by Solutions for Utilities' petition for modification have been addressed in different aspects of this proceeding or will be addressed either

in this proceeding or in the separate, ongoing Commission rulemaking on Rule 21 interconnection matters, R.11-09-011.

46. The issues framed by Sustainable Conservation's petition for modification are addressed in today's decision or will be addressed in the separate, ongoing rulemaking before the Commission, R.11-09-011.

## Conclusions of Law

1. In implementing the amendments to the § 399.20 FiT Program, we rely on federal law, specifically, avoided cost under PURPA, the language of § 399.20 and state laws governing statutory construction, and the policy guidelines adopted herein.

2. The modifications to the § 399.20 FiT Program adopted today comply with federal law by requiring, among other things, that all FERC jurisdictional generators participating in the program register with the FERC as QFs and by adopting a price consistent with PURPA, including the most recent guidance provided by FERC regarding avoided cost pricing for QFs on October 21, 2010 in *California Public Utilities Commission* (2010) 133 FERC ¶61,059 (*FERC Clarification Order*).

3. Based on the *FERC Clarification Order*, the Commission can determine a different avoided cost, differentiated for particular sources of energy based on state procurement requirements.

4. The *FERC Clarification Order* increases the pricing options the Commission can consider when determining the § 399.20 FiT Program price.

5. In implementing the statutory amendments to § 399.20, we are guided by, among other things, the rules of statutory construction together with the Commission's fundamental responsibility to oversee the utility's provision of an adequate supply of safe and reliable electricity at just and reasonable rates.

6. Our primary source of guidance in implementing SB 380, SB 32 and SB 2 1X is derived from the rules of statutory construction.

7. Most significantly for purposes of the § 399.20 FiT Program, SB 32 and SB 2 1X provide new direction to the Commission on how to determine the market price for the § 399.20 FiT Program as electricity purchased under § 399.20 is no longer required to be tied to the MPR. As a result, the potential range of pricing outcomes for the § 399.20 FiT Program has expanded.

8. We should adopt five core policy guidelines as an important secondary source of guidance in implementing SB 380, SB 32 and SB 2 1X. These policy guidelines underlie our adoption of a revised § 399.20 FiT Program price and other program elements.

9. Because the MPR is based on a natural gas-fired electric plant, and not a renewable generator, using the MPR to set § 399.20 FiT Program price fails to achieve our first policy guideline: to "establish a feed-in tariff price based on quantifiable utility avoided costs that will stimulate market demand."

10. Because the MPR does not reflect ongoing changes within the renewable market and, as a result, could potentially result in a price either too low or too high, using the MPR to set § 399.20 FiT Program price fails to achieve our first policy guideline: to "establish a feed-in tariff price based on quantifiable utility avoided costs that will stimulate market demand."

11. The renewable market is sufficiently robust to serve as a point of reference for establishing a market price for the § 399.20 FiT Program, and, therefore, we decline to adopt a pricing proposal that relies upon the MPR.

12. Other proposals that incorporate the MPR, such as those proposals by CALSEIA, Placer County, Silverado Power, the Solar Alliance, Vote Solar Initiative, Clean Coalition, and other parties should not be adopted because these

proposals fail to recognize that the renewable market is sufficiently robust to more accurately reflect generation costs of the FiT Program as compared to the cost reflected in the MPR, that of a natural gas plant.

13. The methodologies presented to determine certain adders, such as those based on technology specific generation, are largely based on general avoided societal costs, not avoided utility costs, and are therefore not the type of avoided costs permitted under PURPA.

14. Because technology specific adders are largely based on general avoided societal costs, these adders are inconsistent with three of the policy guidelines adopted by this decision: (1) Establish a feed-in tariff price based on quantifiable utility avoided costs that will stimulate market demand; (2) Contain costs and ensure maximum value to the ratepayer and utility; and (3) Ensure administrative ease and lower transaction costs for the buyer, seller, and regulator.

15. State law does not specifically direct the Commission to account for the unique cost of each technology. The plain language of § 399.20 does not require that technology-specific costs be included in a FiT Program price methodology.

16. Technology-specific pricing is inconsistent with three of the policy guidelines adopted by in this decision: (1) Establish a feed-in tariff price based on quantifiable utility avoided costs; (2) Contain costs and ensure maximum value to the ratepayer and utility; and (3) Ensure administrative ease and lower transaction costs for the buyer, seller, and regulator.

17. Since renewable generators under the § 399.20 FiT Program are required to sign long-term power purchase agreements (a minimum of 10 years per § 399.20), generators under the § 399.20 FiT Program represent a different value

than the net surplus compensation from net-energy metered customers and, accordingly, should not be paid the same rate.

18. The net surplus compensation rate is inconsistent with our first policy guideline, to "establish a feed-in tariff price based on quantifiable utility avoided costs that stimulate market demand," since the rate is based on the hourly day-ahead electricity market price, or DLAP price, and not the market price for renewable electricity.

19. When combined with SCE's adjustment mechanism, using RAM contracts to set the FiT Program starting price is consistent with the three policy guidelines that relate to choosing a FiT price: (1) Establish a feed-in tariff price based on quantifiable utility avoided costs that results in market demand; (2) Contain costs and ensure maximum value to the ratepayer and utility; and (3) Ensure administrative ease and lower transaction costs for the buyer, seller, and regulator.

20. The pricing methodology we adopt today, Re-MAT, complies with both state and federal law.

21. Because the § 399.20 FiT Program seeks to implement a directive from the Legislature to procure energy from specific sources, renewable generation of 3 MW and less, and to consider the value of different electricity products including baseload, peaking, and as-available electricity, we find using RAM contracts to set the § 399.20 FiT Program starting price, which includes these product types, is the most reasonable alternative to determining the cost of the resources being avoided.

22. A starting price for the § 399.20 FiT Program based on the weighted average of PG&E's, SCE's, and SDG&E's highest executed contract resulting from the RAM auction held in November 2011 is reasonable.

23. Based on the November 2011 auction prices and related information, PG&E's recommendation articulated in its November 2011 comments to use a weighted average of the highest executed RAM contract from each IOU to establish a single, statewide FiT price for each of the three product types provides a reasonable starting price for the FiT Program because the price will be set by the most recent comparable competitive solicitation for renewable generation.

24. It is reasonable to adjust the starting price by time-of-delivery factors based on the generator's actual energy delivery profile to capture the value of each individual generator to the utility.

25. A two-month price adjustment mechanism for each product type should be adopted. The price may increase or decrease from the prior two months' price by increasing or decreasing amounts, depending on the subscription results in each product type for each utility.

26. Each utility should use this adjustment mechanism for each of the three product types.

27. Utilities should be permitted to file a motion to temporarily suspend the program if evidence of market manipulation or malfunction exists.

28. Utilities should incrementally release a portion of their total program capacity allocation each two months for a 24-month period.

29. Utilities should reassign unsubscribed capacity to the same product types starting with Months 25-26 and beyond to prevent gaming, minimize ratepayer exposure to excessively high contract prices, and efficiently manage allocated unsubscribed capacity.

30. To address concerns related to the need and burden of a deliverability study for small distributed generation but, at the same time, ensure compliance

with resource adequacy requirements in § 399.20(i), time-of-delivery factors should be adopted for generators that do not provide resource adequacy.

31. The adopted pricing methodology, Re-MAT, is a market-based pricing methodology that reflects the supply and demand of the renewable electricity market to best ensure ratepayer indifference under § 399.20(d)(4).

32. In order to comply with § 399.20(f), the utilities should make their respective tariffs, which incorporate any program requirements required by statute or by the Commission, available on a first-come-first-served basis.

33. Increasing the maximum project size to 3 MW is reasonable based on the Commission's obligation to implement provisions of the statute and as reliability concerns, if any, are identified and mitigated during the interconnection process.

34. To prevent daisy-chaining, the utilities should add a provision to the § 399.20 FiT Program standard form contract that requires the seller to attest that the project represents the only project being developed by the seller on any single or contiguous piece of property. This provision should also give utilities the authority to deny a tariff request pursuant to § 399.20(n) if the project appears to be part of a larger overall installation by the same company or consortium in the same general location.

35. To effectively prevent potential gaming, generators with a nameplate capacity of 3 MW and under that meet other eligibility criteria for the FiT Program should be prohibited from participating in the RAM Program if the capacity for the relevant FiT product type has not yet been reached.

36. The statutory language, "strategically located," is interpreted to optimize the deliverability of electricity generated at the FiT project to load centers, which means 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.

37. To increase the likelihood that projects participating in the FiT Program are viable projects, it is reasonable to adopt project viability criteria similar to those relied upon in the RAM Program.

38. Electric corporations with less than 100,000 service connections should be removed from the § 399.20 FiT Program.

39. The FiT Program cap should be increased to 750 MW and a proportionate share of the 750 MW (with a proportionate share designated for publicly owned utilities) should be allocated to the three largest electric utilities regulated by the Commission. The allocations, made in accordance with the methodology adopted in D.07-07-027, should be as follows: PG&E 218.8 MW; SCE 226 MW; SDG&E 48.8 MW, for a total of 493 MW.

40. In the interest of consistency and administrative simplicity, it is reasonable to retain the existing allocation methodology, updated in certain respects, adopted by the Commission in D.07-07-027.

41. There is no statutory requirement requiring technological set-asides for the § 399.20 Program. No set-aside (or carve-out) of capacity for specific technologies should be adopted at this time because it is not required by statute or consistent with our policy guidelines for the FiT Program.

42. Due to the various statutory changes, it is logical for PG&E, SCE, and SDG&E to combine existing tariffs setting forth their § 399.20 FiT Programs into a single tariff for each utility.

43. This decision implements SB 32 by eliminating the requirement that participating generators be retail customers to participate in the § 399.20 FiT Program.

44. The FiT Program should not exclude excess sales.

45. This decision implements SB 32 by directing utilities to add an annual inspection and maintenance provision to the standard contracts under the § 399.20 FiT Program.

46. This decision implements SB 32 by directing utilities to add a 10-day reporting requirement to the standard contracts for the § 399.20 FiT Program. The information required is set forth in Attachment A.

47. This decision implements SB 32 by directing utilities to incorporate a provision into their standard form contracts for written notice of a denial of a request for service under the § 399.20 FiT Program which, at a minimum, requires a denial of service under § 399.20(n) be provided in writing to the producer.

48. This decision implements SB 32 by directing utilities to incorporate a provision into their standard form contracts for termination of service under the § 399.20 FiT Program.

49. This decision implements SB 32 pertaining to expedited interconnection by clarifying that parties should rely on the existing provisions of Tariff Rule 21 (rather than those under review in R.11-09-011) until the Commission finalizes its ongoing efforts to refine Tariff Rule 21 and expedited interconnection in R.11-09-011. Until the Commission makes a final determination in R.11-09-011, utilities should also allow generators to choose which interconnection processes to use, either the process set forth in Tariff Rule 21 or the FERC interconnection procedures.

50. To implement § 399.2(k) requiring refund of CSI and SGIP incentives, a generator that previously received incentives under CSI or SGIP can participate in the § 399.20 FiT Program and will owe no refund if it has been online and

operational for at least ten years from the date it first received the incentive. Net-energy metering customers can participate in the § 399.20 FiT Program but should first terminate participation in net-energy metering.

51. A participating generator should register with FERC as a QF. Generators may utilize FERC's self-certification process by filling out FERC's Form 556.

52. The program Rules in place when a contract is executed apply.

53. The Commission gave full consideration to all pricing options presented in the proceeding, including that of an "administratively determined, avoided-cost based pricing mechanism."

54. The petition for modification of D.07-07-027 filed by Solutions for Utilities on June 18, 2010 should be denied.

55. The petition for modification of D.07-07-027 filed by Sustainable Conservation on June 29, 2011 should be denied.

56. Any location or transmission adder must be based on costs that are found to be actually avoided by the utilities.

57. § 399.20(f) discusses the obligation of the utilities to offer their tariffs on a first-come-first-served basis, and does not discuss the Commission's authority to impose pricing, procurement, or other program requirements for the FiT.

58. The Commission has broad authority over public utilities, including authority over the utilities' resource portfolios and procurement planning, and in implementing the RPS Program. The Commission has the authority to act even in cases where there is no express statutory authorization so long as the additional power and jurisdiction the Commission exercises are cognate and germane to the regulation of public utilities, and do not contravene or disregard an express legislative directive.

## O R D E R

1. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company shall incorporate the starting price for three product types, the adjustment mechanism, and their program capacity allocation, and incremental capacity releases into their tariffs and standard contracts for the § 399.20 Feed-in Tariff (FiT) Program being developed in this proceeding in accordance with the schedule set forth in the January 10, 2012 Administrative Law Judge ruling. The Commission will review these provisions and, in a separate decision accept, reject, or modify the provisions. Related FiT tariff modifications will also be addressed in this separate decision.

2. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company shall make the Feed-in Tariff price and available capacity, including any results from the price adjustment mechanism or the capacity reassignment methodology, continuously available to the public on their websites by the first business day of each two-month period.

3. Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDG&E) shall convene stakeholders within the first year of the § 399.20 Feed-in Tariff Program to solicit market experience with the pricing adjustment mechanism. PG&E, SCE, and SDG&E shall also establish an online mechanism for continuous receipt of public input on the program. To the extent that changes to the price adjustment, capacity allocation mechanism, or other aspects of the program are needed to improve the program, PG&E, SCE, and SDG&E are permitted to file a joint Advice Letter seeking specific changes.

4. Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDG&E) shall offer

two sets of time-of-delivery factors: one for generators that do not provide resource adequacy and another for generators that do provide resource adequacy. PG&E, SCE, and SDG&E shall add a provision reflecting delivery factors to the § 399.20 Feed-in Tariff (FiT) Program standard form contract and/or tariff that is being developed in this proceeding in accordance with the schedule set forth in the January 10, 2012 Administrative Law Judge ruling. The Commission will review this provision and, in a separate decision accept, reject, or modify the provision. Related FiT tariff modifications will also be addressed in this separate decision.

5. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company shall add a provision reflecting the increase in eligible generator projects to three megawatts to the § 399.20 Feed-in Tariff (FiT) Program standard form contract and/or tariff that is being developed in this proceeding in accordance with the schedule set forth in the January 10, 2012 Administrative Law Judge ruling. The Commission will review this provision and, in a separate decision accept, reject, or modify the provision. Related FiT tariff modifications will also be addressed in this separate decision.

6. Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDG&E) shall add a provision to the § 399.20 Feed-in Tariff (FiT) Program standard form contract and/or tariff that requires the seller to attest that the project represents the only project being developed by the seller on any single or contiguous piece of property. This provision will give PG&E, SCE and SDG&E the authority to deny a tariff request pursuant to § 399.20(n) if the project appears to be part of a larger overall installation by the same company or consortium in the same general location. This provision shall permit generators to contest a denial under

§ 399.20(n) through the Commission's standard complaint procedure set forth in the Commission's Rules of Practice and Procedure. The Commission will review this provision and, in a separate decision, accept, reject, or modify the provision. Related FiT tariff modifications will also be addressed in this separate decision.

7. Within 90 days of the effective date of this decision, Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company shall file a Tier 1 Advice Letter restricting the Renewable Auction Mechanism (RAM) to generators with a nameplate capacity of greater than three megawatts and that do not satisfy the Feed-in Tariff eligibility criteria. This change will not affect the upcoming RAM auction scheduled to close in May 2012 but will take effect in time for the third RAM auction scheduled for the end of 2012.

8. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company shall add a provision to the § 399.20 Feed-in Tariff (FiT) Program standard form contract and/or tariff addressing the prerequisite that generators must be "strategically located." This means that the generator be (1) interconnected to the distribution system, as opposed to the transmission system, and (2) sited near load, meaning sited in an area where interconnection of the proposed generation requires $300,000 or less of upgrades to the transmission system. Such a provision shall be presented to the Commission for consideration in accordance with the schedule set forth in the January 10, 2012 ALJ ruling. The Commission will review this provision and, in a separate decision accept, reject, or modify the provision. Related FiT tariff modifications will also be addressed in this separate decision.

9. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company shall add a provision reflecting the

adopted project viability criteria to the § 399.20 Feed-in Tariff (FiT) Program standard form contract and/or tariff that is being developed in this proceeding in accordance with the schedule set forth in the January 10, 2012 Administrative Law Judge ruling. The Commission will review this provision and, in a separate decision accept, reject, or modify the provision. Related FiT tariff modifications will also be addressed in this separate decision.

10. Within 90 days of the effective date of this decision and pursuant to § 399.20(c), electrical corporations with less than 100,000 service connections within this state shall file Tier 1 Advice Letters withdrawing their tariffs relevant to the § 399.20 Feed-in Tariff Program.

11. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company shall modify tariff and/or contract provisions to reflect the consolidation of tariffs applicable to public water or wastewater agencies and tariffs for other customers in the § 399.20 Feed-in Tariff (FiT) Program. These modifications shall be incorporated into the standard form contract that is being developed in this proceeding in accordance with the schedule set forth in the January 10, 2012 ALJ ruling. The Commission will review these provisions and, in a separate decision accept, reject, or modify these provisions. Related FiT tariff modifications will also be addressed in this separate decision.

12. Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDG&E) shall remove, as necessary, references to retail customers in the Feed-in Tariff (FiT) Program standard form contract and/or tariff that is being developed in this proceeding in accordance with the schedule set forth in the January 10, 2012 ALJ ruling. PG&E, SCE, and SDG&E are required to offer generators two options: either full

sales or excess sales. The nameplate capacity of all generators participating in this program is limited to three megawatts, regardless of the sales option. The Commission will review this provision submitted by the utilities and, in a separate decision accept, reject, or modify the provision. Related FiT tariff modifications will also be addressed in this separate decision.

13. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company shall add a provision reflecting the annual inspection and maintenance reporting to the § 399.20 Feed-in Tariff (FiT) Program standard form contract and/or tariff that is being developed in this proceeding in accordance with the schedule set forth in the January 10, 2012 Administrative Law Judge ruling. The Commission will review this provision and, in a separate decision accept, reject, or modify the provision. Related FiT tariff modifications will also be addressed in this separate decision.

14. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company shall add a provision reflecting the 10-day reporting requirement for requests for service in the § 399.20 Feed-in Tariff (FiT) Program standard form contract and/or tariff being developed in this proceeding in accordance with the schedule set forth in the January 10, 2012 Administrative Law Judge ruling. The Commission will review this provision and, in a separate decision accept, reject, or modify the provision. Related FiT Tariff modifications will also be addressed in this separate decision.

15. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company shall add a provision regarding denial of service by the utility to the § 399.20 Feed-in Tariff (FiT) Program standard form contract and/or tariff that is being developed in this proceeding in accordance with the schedule set forth in the January 10, 2012 Administrative Law Judge

ruling. The Commission will review this provision and, in a separate decision accept, reject, or modify the provision. Related FiT tariff modifications will also be addressed in this separate decision.

16. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company shall add a provision reflecting contract termination to the § 399.20 Feed-in Tariff (FiT) Program standard form contract and/or tariff that is being developed in this proceeding in accordance with the schedule set forth in the January 10, 2012 Administrative Law Judge ruling. Other termination provisions may be included in the standard form contract. The Commission will review this provision and, in a separate decision accept, reject, or modify the provision. Related FiT tariff modifications will also be addressed in this separate decision.

17. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company shall add a provision reflecting the eligibility to participate in the § 399.20 Feed-in Tariff (Fit) Program based on past participation and receipt of California Solar Initiative and Small Generator Incentive Program incentives in the § 399.20 FiT Program standard form contract and/or tariff that is being developed in this proceeding in accordance with the schedule set forth in the January 10, 2012 Administrative Law Judge ruling. The Commission will review this provision and, in a separate decision accept, reject, or modify the provision. Related FiT tariff modifications will also be addressed in this separate decision.

18. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company shall be authorized to file a motion to temporarily suspend the Section 399.20 Feed-in Tariff Program when evidence of market manipulation or malfunction exists. The motion shall be served on the

service list of this proceeding or any successor proceeding. This authorization shall be incorporated into the standard form contract and/or tariff that is being developed in this proceeding in accordance with the schedule set forth in the January 10, 2012 ALJ ruling. The Commission will review this provision and, in a separate decision accept, reject, or modify the provision.

19. The Joint Motion of the Center for Energy Efficiency and Renewable Technologies; AG Power Group, LLC; Sustainable Conservation; Agricultural Energy Consumers Association; Green Power Institute; California Wastewater Climate Change Group; California Farm Bureau Federation; Fuel Cell Energy; and FlexEnergy, Inc., for a Ruling Directing the Consideration of an Administratively determined Avoided Cost Pricing Methodology for the Renewable FIT at a January 2012 Workshop that Would be Part of the Record for the Decision on the Renewable FIT filed on December 19, 2011 is denied.

20. The Petition for Modification of D.07-07-027 filed by Solutions for Utilities on June 18, 2010 is denied.

21. The Petition for Modification of D.07-07-027 filed by Sustainable Conservation on June 29, 2011 is denied.

22. Rulemaking 11-05-005 remains open.

The order is effective today.

Dated May 24, 2012, in San Francisco, California.

MICHAEL R. PEEVEY
President
TIMOTHY ALAN SIMON
MICHEL PETER FLORIO
CATHERINE J.K. SANDOVAL
MARK J. FERRON
Commissioners

# Attachment A - 10-day reporting requirement to tariffs under the § 399.20 FiT Program R.11-05-005

Link to Pro Forma FiT PPA until actual PPA is public.

Because of small size of FiT projects, include capacity to two decimal places.

| A | B | C | D | E | F | G | H | I | J | K | L |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Contract Effective Date | Seller Name and Project Name | FiT PPA | Status (On-Schedule, Delayed, Operational, Terminated) | IOU | Contract Capacity (MW) | Expected Generation (GWh/yr) | Technology | Vintage | Contract Term (years) | Location (city and county) | Contracted Commercial Operation Date (COD) |
| 7/15/12 | AES Delano | Download | Operational | SDG&E | 1.50 | 34 | Solar PV | existing | 10 | Delano, Kern County | 01/01/13 |
| | | | Terminated | PG&E | | | Wind | new | 15 | | |
| | | | Delayed | SDG&E | | | Geothermal | | 20 | | |
| | | | On-Schedule | | | | Biogas | | | | |
| | | | | | | | Biomass | | | | |
| | | | | | | | Small hydro | | | | |
| | | | | | | | Solar Thermal | | | | |
| | | | | | | | Landfill Gas | | | | |
| | | | | | | | Wave | | | | |
| | | | | | | | Tidal | | | | |
| | | | | | | | | | | | |

**NOTE: Columns shaded in red are new fields added specifically for Feed in Tariff projects. Columns N [6-month Regulatory Delay] through R [Stage in Interconnection Process] should be updated twice yearly concurrent with other existing RPS reporting requirements.**

| M | N | O | P | Q | R | S | T | U |
|---|---|---|---|---|---|---|---|---|
| Actual Commercial Operation Date (COD) | 6-month Regulatory Delay (Y/N) | Reason for Regulatory Delay (Site, Permit, Interconnection, Transmission) | Interconnection Agreement Signed (Y/N) | Interconnection Agreement Application Completed (Y/N) | Stage in Interconnection Process (Study, Agreement, Construction, Completion) | Full Buy/Sell or Excess Sales | Product Category (Baseload, peaking intermittent, non-peaking intermittent) | Full Capacity Deliverability Status (FCDS) or Energy-Only |
| 1/15/2013 | N | - | Y | Y | Completion | Full Buy/Sell | Baseload | FCDS |
| | Y | Site | N | N | Agreement | Excess Sale | Peaking intermittent | Energy-only |
| | Y | Permit | | | Construction | | Non-Peaking intermittent | |
| | Y | Interconnection | | | Feasibility Study | | | |
| | | Transmission | | | System Impact Study | | | |
| | | | | | Facilities Study | | | |
| | | | | | Fast Track | | | |
| | | | | | Supplemental Review | | | |
| | | | | | Simplified Review | | | |
| | | | | | Cluster Study Phase I | | | |
| | | | | | Cluster Study Phase II | | | |

**(End of Attachment A)**