PUBLIC UTILITIES COMMISSION
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TO PARTIES OF RECORD IN RULEMAKING 11-05-005

This is the proposed decision of Administrative Law Judge (ALJ) DeAngelis. It will not appear on the Commission's agenda sooner than 30 days from the date it is mailed. The Commission may act then, or it may postpone action until later.

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

Parties to the proceeding may file comments on the proposed decision as provided in Article 14 of the Commission's Rules of Practice and Procedure (Rules), accessible on the Commission's website at www.cpuc.ca.gov. Pursuant to Rule 14.3, opening comments shall not exceed 15 pages.

Comments must be filed pursuant to Rule 1.13 either electronically or in hard copy. Comments should be served on parties to this proceeding in accordance with Rules 1.9 and 1.10. Electronic and hard copies of comments should be sent to ALJ DeAngelis at rmd@cpuc.ca.gov and the assigned Commissioner. The current service list for this proceeding is available on the Commission's website at www.cpuc.ca.gov.

/s/ KAREN V. CLOPTON
Karen V. Clopton, Chief
Administrative Law Judge

KVC:jt2

Attachment

Decision **PROPOSED DECISION OF ALJ DeANGELIS** **(Mailed 3/20/2012)**

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Continue Implementation and Administration of California Renewables Portfolio Standard Program.	Rulemaking 11-05-005 (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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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 principle 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 monthly price adjustment

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[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 increases or decreases the starting price for each product type 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 energy resources" under the RPS Program with an effective capacity of

[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 !!!-12 First Extraordinary Session, Stats. 2011, Ch.1) unless otherwise noted.

3 megawatts (MW) or less and, among other things, strategically located on the distribution grid.[4] Today's decision refers to the Commission's on-going implementation work regarding its program 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

[4] *See* § 399.20(a) and (b)(1)-(4).

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

an electric corporations' 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 required 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 from 1.5 MW. Some of the most controversial issues relate to price. Many of

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[6] More details regarding the RPS Program's target compliance periods 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.

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 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, on-going Commission proceeding , Rulemaking (R.) 11-09-011,[9] which, among other things, "seeks to review, and if necessary revise Rule 21 to ensure that the interconnection process is timely, non-discriminatory, cost-effective, and transparent."[10]

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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).

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

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 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

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

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 $93.75 per megawatt hour (MWh) pre time-of-delivery adjustments. Among other things, Resolution E-4442 ordered each utility to update its tariffs for the § 399.20 FiT Program, as required by D.07-07-027, consistent with the 2011 MPR.[14]

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[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 feed-in tariff program set forth in Public Utilities Code section 399.20."

[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."

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 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

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[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.

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 Bell 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 § 399.20, as amended.

3. Parameters in Implementing the § 399.20 Feed-In Tariff Program

In implementing the amendments to the § 399.20 FiT Program, we rely on federal law, specifically, avoided cost under the Public Utility Regulatory Policies Act of 1978 (PURPA).[17] We also rely upon the state laws governing statutory

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

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 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]

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

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[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).

[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.

provided by the FERC regarding avoided costs 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 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

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[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.

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

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

> 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 wide degree of latitude in setting the avoided cost. We apply the same logic for the § 399.20 FiT Program. Specifically, based on FERC's clarification, the Commission can determine a different avoided cost, differentiated for particular sources of energy as long as state law has imposed an obligation on the utility to purchase energy from those sources of energy. Thus the Commission can have multiple different avoided costs, and we need not be restricted by the avoided cost adopted in D.10-12-035.[26] In addition, the Commission can utilize a multi-tiered avoided cost rate structure. This clarification increases 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 electricity at just and reasonable rates. Today, in implementing the statutory amendments to § 399.20, we are guided by, among other things, the

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25 *FERC Clarification Order* at 26.

26 Opinion Adopting Proposed Settlement, (December 12, 2010) in R.06-02-013, R.04-04-003, R.04-04-025, R.99-11-022, *Application of Southern California Edison Company (U338E) for Applying the Market Index Formula and As-Available Capacity Prices adopted in D.07-09-040 to Calculate Short-Run Avoided Cost for Payments to Qualifying Facilities beginning July 2003 and Associated Relief; and Related Matters*.

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.[27]

[27] *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.

Although the courts remain the ultimate arbiters of statutory meaning, courts accord deference to the Commission's reasonable interpretation of statutes.[28] 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.'"[29]

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

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

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[28] *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.

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

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.[30] Specifically, in D.07-07-027 the Commission found that the pricing for electric generation under § 399.20 was the MPR,[31] adjusted for time-of-delivery factors.[32] Since the cross-reference to § 399.15 has been removed pursuant to SB 2 1X, electricity purchased under § 399.20 is no longer tied to the MPR as it was 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:[33]

> (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

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[30] 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.

[31] 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.

[32] 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.

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

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.*

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. 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 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

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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.

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 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 (CO2) and other environmental inputs that capture costs related to nitrogen oxide (NOx), sodium oxide (SOx), particulate matter (PM10), 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

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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.

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, NOx, CO2, SOx, VOCs, and PM10 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 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

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

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 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

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

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.

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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.*

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 (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

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40 FuelCell Energy March 7, 2011 brief at 15.

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*.

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 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.)

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

(6) 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

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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.

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:

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.[43] 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

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[43] 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.

located in that area."[44] 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.

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 Instead, it reflects the costs of a different energy market,

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

fossil fuels. Specifically, the MPR does not reflect on-going 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 market used for the MPR, the 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 for these adders were generally based on avoided *societal* costs, and not *ratepayer or utility costs*, which might be argued to be inconsistent with the federal requirement under PURPA.

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 costs to utilities or ratepayers. In addition, these adders could increase the contract price above the resource's actual costs and lead to overpayment. As discussed below, market-based pricing calibrates the FiT price to market prices and to market demand, which leads both to reasonable ratepayer costs and prices that can work 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.

Regarding the state law issue, the parties do not address the fact that, as written, state law does not specifically direct the Commission to account for the unique cost of each technology. The plain language of § 399.20 neither directs nor suggests that technology-specific costs be included in a FiT Program price methodology.

Furthermore, while these parties refer the Commission to l§ 399.20(d)(1) to support their position on consideration of technology classifications, the parties failed to provide evidence in the proceeding consistent with the statutory mandate. 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."

However, no party presented evidence that their proposals addressed specific "environmental compliance costs." Rather parties presented evidence on the general environmental societal values associated with their particular generation and incorrectly characterized this provision as addressing current and anticipated environmental costs. The parties' proposals, therefore, are not supported by the plain language of the statute.

Parties suggested that federal law supports technology-specific prices. The reasoning here is incomplete. While federal law, as discussed above, provides the Commission with the latitude to take into account the state's legislative energy procurement mandates when establishing avoided costs, the state statute, as codified in § 399.20, does not direct the Commission to consider technology-specific costs when determining the § 399.20 FiT Program price.

In addition to the statutory guidance, technology-specific pricing is inconsistent with three of the policy guidelines established in 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.

Technology-specific pricing does not establish a § 399.20 FiT Program price based on the renewable market and competitive pressures, but rather uses administratively-determined calculations to establish a price based on the costs plus a fair rate of return to build and operate a specific technology, which removes any incentive or ability for competition to decrease 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 administrative complexity and increases the transaction costs for the regulator, who is responsible for calculating each technology's cost when the § 399.20 FiT Program begins, and then conducting periodic updates throughout the program.

Accordingly, we do not adopt technology-specific pricing as it fails to comply with federal and state law and with our policy guidelines for implementing the § 399.20 FiT Program.

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 DALP 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 § 399.30 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 either inconsistent with existing law or require more development. Regarding the transmission adder, we find that the record does not support a determination that the transmission costs for particular RAM contracts constitute the avoided transmission costs for renewable FiT generators under the law. As discussed previously regarding Clean Coalition's suggested location adder, we agree with the concerns expressed by SCE and the other utilities that additional scrutiny is needed before the Commission adopts a location adder. Furthermore, the requirement that projects in the § 399.20 FiT Program be "strategically located," as discussed separately in Section 10, addresses the concerns that parties and Staff sought to address through a locational adder, which is to provide an incentive to generators to locate 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 a monthly market 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. Starting with 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. We further find that a FiT price that reflects the renewable market ultimately more fully reflects avoided costs under federal law.

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

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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.

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.

Our finding is based on the fact that the market segment represented by RAM more closely represents the market segment covered by § 399.20 than other pricing proposals, including pricing proposals relying on the MPR. The discussion above at Section 6 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. Nevertheless, while not identical, the RAM Program presents the closest comparison and, as such, we find it reasonable to define Re-MAT, which includes the market adjustment mechanism, as an avoided cost, as required under federal law.

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 long-term market price for fixed price contracts pursuant to an electrical corporation's general procurement activities. The Commission has considered 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 includes, as embedded within it, general costs associated with producing renewable energy since our goal is to pay generators the price needed to build and operate the generation facility. We do not find, however, that specific costs, such as compliance costs in a particular air quality management district, are necessarily captured by the RAM methodology. No party presented data on such 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 does not distinguish among different product types and only offers one price. In an effort to better capture the value provided by different technology types, § 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. 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 decline to adopt such an option because the November 2011 RAM contract prices contained insufficient market information for the three product types to render this option viable. 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 distributed generation.

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 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). [46] PG&E, SCE, and SDG&E shall incorporate this starting price, adjustment mechanism, and incremental capacity releases, as discussed below, into their tariffs and standard contracts for the § 399.20 FiT Program.

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

We also adopt a monthly 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,[47] and we adopt SCE's proposal, in part. Under the adopted price adjustment mechanism, the monthly price for a utility's product type may increase or decrease from the prior month's price by increasing amounts as long as at least five eligible projects with different project sponsors are in the utility's queue for that product type. Each utility will make the monthly FiT prices publicly available on its website by the first business day of each month.

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[46] 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 has provided the Commission with cost data for the contracts it expects to execute by March 30, 2012 but had not yet executed contracts from the first RAM auction. The Commission's Energy Division Staff is authorized to recommend updates to relevant date in this decision, if necessary, after SDG&E executes its RAM contracts.

[47] SCE August 5, 2011 comments at proposed tariff "Special Condition #8 MP FiT Pricing and Cumulative Procurement Targets," Appendix A Schedule MP FiT, Sheet 5.

A price adjustment mechanism will enable the FiT price to quickly respond to market conditions while also preventing gaming.[48] The FiT Program's price is designed to only increase or decrease provided that a defined level of market interest exists for a product type (at least five project sponsors), but no projects enter into contracts at the offered Re-MAT price, which suggests the Re-Mat price is either too low or too high.

As part of today's decision, interested generators that meet the program's minimum project viability criteria (Section 11) 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-serve basis for each product type. At the beginning of each month, the utility will offer generators a FiT contract at that month's Re-MAT price, in order of the queue. A generator can accept or reject the price. If a generator accepts the price, it enters into a FiT contract. If the generator declines a contract at that price, it maintains its position in the queue the next month.

The price adjustment will be triggered only after least five eligible projects are sponsored by different developers in the queue. If there are less than five eligible projects sponsored by different developers for any monthly offering, then the Re-MAT price will remain the same the next month. However, if the threshold of five eligible projects with different sponsors is achieved, yet no sponsor enters into a FiT contract for at the monthly price, then a price increase will be triggered the following month. Or, if the threshold of five eligible

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[48] For example, a price adjustment mechanism should not incentivize generators to purposefully withhold executing a contract in order to force a price increase.

projects with different sponsors is achieved and the full monthly capacity assignments subscribed for a product type, a price decrease will be triggered the following month.

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

6.4.1. Increased Price - Illustrated

If no program subscription results at the existing price in any product type and if there are at least five eligible projects from different sponsors, the price will increase each consecutive month until there is at least one program subscription. The following serves to illustrate how this mechanism works to increase the price:

- Month 1: Starting Price ($89.23/MWh). If no subscriptions result, then Month 2 price increases as follows:
- Month 2: Starting Price + $4.00/MWh (total $4.00/MWh increase over prior month) and, if no subscription results, Month 3 price increases as follows:
- Month 3: Starting Price+ $12.00 (total of $8.00 increase over prior month) and, if no subscription results, Month 4 price increases as follows:
- Month 4: Starting Price + $24.00 (total of $12.00 increase over prior month) and, if no subscription results, Month 5 price increases as follows:
- Month 5: Starting Price + $40.00 (total of $16.00 increase over prior month) and, if no subscription results, Month 6 price increases as follows:
- Month 6: Starting Price + $60.00 (total of $20.00 increase over prior month).

The price increase mechanism may continue indefinitely. Any program capacity not subscribed in a month will roll over into the next month. See

Section 13.4 for a discussion about reassigning unused capacity. In the event that there is one subscription in Month 4, for example, then the price in Month 5 will stay the same. If there are no subscriptions in Month 5, and there remain at least five projects from different sponsors in that product type's queue, the size of the incremental price increase will reset to $4/MWh.

It is our expectation that more expensive technologies may gain the opportunity to participate in the FiT Program by, for example, Month 5, 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. Additional time may be required to reach that price if less expensive technologies subscribe to the product type.

6.4.2. Decreased Price - Illustrated

If full subscription results in any product type and if at least five eligible projects with different sponsors are in a utility's queue for a product types, the price for that product type will decrease in the subsequent month. The price will stay the same if full subscription is not reached in the prior month. The following serves to illustrate how this mechanism works to decrease the price:

- Month 1: Starting Price ($89.23/MWh). If full subscriptions result, then Month 2 price decreases as follows:
- Month 2: Starting Price minus $4.00 (total $4.00 decrease from prior month) and, if full subscription results, Month 3 price decreases as follows:
- Month 3: Starting Price minus $12.00 (total of $8.00 decrease from prior month) and, if full subscription results, Month 4 price decreases as follows:
- Month 4: Starting Price minus $24.00 (total of $12.00 decrease from prior month) and, if full subscription results, Month 5 price decreases as follows:

- Month 5: Starting Price minus $40.00 (total of $16.00 decrease from prior month) and, if full subscription results, Month 6 price decreases as follows:
- Month 6: Starting Price minus $60.00 (total of $20.00 decrease from prior month).

6.5. Assignment of Capacity to Three Products and Incremental Release Capacity

In addition to allocating the program capacity among the three utilities, as discussed in Section 13, we direct utilities to assign a portion of this allocated capacity to three product types over 12 months, i.e., baseload, peaking as-available, and non-peaking as-available. In doing this, we consider assigning the remaining capacity over a limited time period in an effort to stimulate the market for small renewable distributed generation by providing an adequate supply of available capacity to each product type.

SCE, CEERT, CALSEIA, and FuelCell Energy suggest a similar approach. To implement this directive, each utility must divide its total program capacity by 12 and then assign one third into each product type, with a minimum of 3 MW for each product type in the first month. Each utility is directed to track FiT subscriptions and publicly notice the amount of capacity remaining in each product type on a monthly basis on its website by the first business day of each month.

If no contracts are executed in a given month, the capacity (not under contract) will be divided evenly across all remaining program months within that product type. At the same time, the utilities are directed to keep at least 3 MW in each product type.

To prevent gaming, minimize ratepayer exposure to excessively high contract prices, and efficiently manage unsubscribed for capacity, the utilities will be allowed to reassign capacity to the different product types after the expiration of 12 program months. The utilities will use the following reassignment formula: after Month 12, the utilities may reassign any capacity from a product type that has received minimal to no subscriptions during the previous 12-month period. In Month 13, the utilities should reassign 5% of the capacity from these products to other products with a combination of the highest average net market value[49] and the most robust market subscription. In Month 14, the utilities should reassign 10% of the remaining capacity. In Month 15, the utilities should reassign 20% of the remaining capacity, then 40%, and so on.

This reassignment is designed to minimize ratepayer exposure to a large number of high priced contracts while ensuring that capacity is available for that product type. As stated above, this methodology reassigns capacity to product types that offer the highest net market value or reflect the most robust market interest but only after a certain amount of time has expired so that the market segment has a reasonable amount of time to respond.

6.6. Program Forums and Future Modifications to the Monthly 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 monthly pricing adjustment

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[49] The net market value (NMV) metric should be based on the following calculation that incorporates the benefits and costs of the product offered, where all units are in \$/MWh: Net Market Value = (E+C) – (P+T+C+I). Where, E = Energy Value, C = Capacity Value; and where, P = post-TOD adjusted PPA price, T = transmission network upgrade costs, C = congestion costs, and I = integration costs.

mechanism. The utilities and market participants should address specific elements of the adjustment mechanism, such as the adjustment time period (e.g., each month versus each quarter), the amount of monthly price increase or decrease, and any other implementation aspect of the adjustment mechanism. To the extent that changes to the adjustment mechanism 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 on its own motion for consideration by the Commission.

6.7. 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."[50] 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.[51] Notably, at this time, generators interconnecting through the Tariff Rule 21 do not have the option to apply for a deliverability study.

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

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

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 requires application fees and deposits to stay in the study process. The total study 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 of these burdensome requirements for small generators, the CAISO is currently conducting a stakeholder process to evaluate alternative paths to deliverability for distributed generation.

In November 2011 comments, PG&E proposed a solution to address 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 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 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.

6.8. 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."[52] Some parties, including CEERT, stated that ratepayers are indifferent to any avoided cost rate. Other parties found ratepayers to be 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.[53] Other parties, such as SCE, suggest that a market-based pricing

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[52] § 399.20(d)(3).

[53] "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

Footnote continued on next page

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."[54] Similarly, we find today that Re-MAT, a market-based pricing methodology, best ensures ratepayer indifference under § 399.20(d)(3). A market-based approach is in the best interest of California electricity customers. We now know that the state's renewable energy market has matured and prices have decreased.[55] 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 participation in the market. In contrast, administratively-determined pricing is static and, as a

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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.)

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

55 *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).

result, administrative guesses at prices 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)(3) by reflecting the supply and demand of the renewable generation market.

6.9. First-Come-First-Served

Re-MAT is consistent with the requirement that electric corporations make FiT tariffs available on a "first-come-first-served basis." The "first-come-first-served" requirement is set forth in § 399.20(f). In accordance with the rules of statutory construction, this provision must be read in manner consistent with all other provisions of the statute. This provision can not be applied to the § 399.20 FiT Program in isolation. For example, it is an untenable reading of that statute that contracts be accepted by electrical corporations on a first-come-first-served basis without regard to price. Price is a key component of the statute and, only after generators enter into contracts under the adopted pricing mechanism and any other statutory prerequisites, would the first-come-first-served provision apply.

On the other hand, this provision functions to restrict the Commission from creating program requirements that interfere with the first-come-first-served requirement as it applies to the program as a whole. For example, as discussed earlier in this decision, in the absence of any specific legislative directive, a Commission requirement that pricing be distinguished based on technology-specific basis would interfere with the application of the statutory provisions requiring first-come-first-served. The statute, however, allows for first-come-first-served on a product specific basis because the statute specifically directs the Commission to consider the value of different electricity products including baseload, peaking as-available, and non-peaking as-available electricity.[56]

For these reasons, we find that Re-MAT, which includes consideration of product types but not specific technologies, is consistent with the first-come-first-served provision set forth in § 399.20(f).

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

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[56] § 399.20(f).

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 the absence of any identified reliability concerns. 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 above 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 load to locate near load centers. The meaning of "strategically located," is further discussed in Section 10, below. 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 size limitation corresponds to the nameplate capacity of the facility.

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 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 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 size restrictions.

Accordingly, the utilities shall add a provision titled, generally, "Seller Representation" to the § 399.20 FiT Program 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 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 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, 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.[57] 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.

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[57] 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.

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 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 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. 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.[58] In contrast, the specific statutory 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."[59]

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.[60] 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.

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58 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."

59 § 399.3020(b)(3).

60 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."

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, strategically located to optimize the deliverability of electricity generated at the FiT facility to load centers, means that a generator must be interconnected to the distribution system, as opposed to the transmission system, and, in addition, must be sited near load, meaning not in an area with such low load that interconnection of the proposed generation would require utilization of the transmission system and new transmission infrastructure.

To implement our interpretation of subsection (b)(3), we find that if a project's most recent interconnection study shows that the project requires transmission system network upgrades, that project will no longer be eligible for the § 399.20 FiT Program. As described in Section 11, below, one project viability criteria is that a project must have completed its system impact study or cluster study phase I (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. 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 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 not in an area with such low load that interconnection of the proposed generation would require utilization of the transmission system and new transmission infrastructure or transmission system network upgrades. 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.

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

In March 2011 briefs, SunEdison, CALSEIA, and Joint Solar Parties suggest 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 agree 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 state 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) Bid fee: $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) Commercialized Technology: Attest that: project is based on commercialized technology with at least two installations in the world;
6) Online Date: 18 months with one 6-month extension for regulatory delays;
7) Seller Concentration: None adopted. 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.

This decision adopts the above-noted project viability criteria 1 through 6. No viability criterion is adopted for seller concentration (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 does not adopt a seller concentration limit since other program requirements, such as "strategically located" and the three product types, which are discussed elsewhere in this decision, are designed to encourage a diversity of sellers and technologies in the program. We also note that in the RAM decision, D.10-12-048, we declined to adopt a seller concentration limit because such a criterion could limit competition. Furthermore, since the program's total capacity will be subdivided by the utilities into product types and assigned on a monthly basis, a seller concentration limit is not warranted.

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 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.

12. 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)[61] 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 voluntary because, although small, it continues to be an important component of

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[61] 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.

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 will 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.

13. 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. 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 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 issue raised by parties.

13.1. 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 an increased cap. Some suggest that the cap should be further increased to an amount above 750 MW. We address these various questions below.

We do not adopt the recommendation by some parties, including Vote Solar Initiative, Solar Alliance, Sierra Club, Clean Coalition, to increase the cap beyond 750 MW. The Legislature has created a specific program under § 399.20 limited to 750 MW and this program is, notably, a must-take obligation by utilities. Based on the plain statutory language of § 399.20, this result cannot be reached.

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 agree to address this transition matter. Accordingly, 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. If a contract is terminated at a future date, then the utility is obligated to re-contract for that capacity.

13.2. 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 utilities' 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.

13.3. 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) <u>2010 Coincident Peak-Hour Demand:</u>[62]

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

(2) <u>Total Statewide Demand:</u>

Summer 2010 Peak: 60,797 MW[63]

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[62] *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).

(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
SCE: 49% or 247.6 MW

13.4. 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

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[63] *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

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 project 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 resources.

We decline to adopt a set aside for biogas. The § 399.20 Program applies equally to all electric generation facilities and must be made available on a first-come-first-served basis. Subsection (f) of § 399.20 provides, in relevant part, that "an electrical corporation shall make the tariff available to the owner or operator of a electric generation facility with the service territory of the electric corporation, upon request, on a first-come-first-served basis, …" In the absence of any statutory provision requiring us to, at least, consider a set aside, we find that a set aside program for a particular technology is inconsistent with the requirement that the program be made available on a first-come-first-served basis.

However, as discussed previously, we adopt three product types for the expanded FiT Program and require at least 3 MW in each type. 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, it dedicates a certain portion of the capacity allocation to each product type, which could be viewed as a set aside that is consistent with § 399.20(d)(2)(C).[64] The allocation will remain in the designated product type unless there is no subscription in that type for more than 12 months. Re-MAT also could benefit bioenergy and the other technologies because it allows renewable resources to compete against other similarly-valued renewable resources, rather than the entire renewable 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 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.

13.5. 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

[64] § 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.

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.

14. 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 interpreted the "owned and operated" requirement broadly 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:…"[65]

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 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 12 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 customer into the § 399.20 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 submitted by the utilities and, in a separate decision accept, reject, or modify the

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65 Additional criteria are omitted and are not relevant for purposes of this discussion.

provision. Related FiT tariff modifications will also be addressed in this separate decision.

15. 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 …"[66] 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

[66] § 399.20(f).

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 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 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. 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 California Alternative Rates for 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 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.

17. 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. Specifically, 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").[67] 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 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 § 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

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[67] 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.

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 when brought to our attention in R.11-9-011.

The form to be used by all electric corporations to post information on the internet is included herein at Attachment A.[68]

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 standard form contract 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.

18. 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.

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[68] 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.

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 IOUs 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.

19. 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 an 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 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).[69] 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 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. Contract Termination Provisions

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 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

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[69] § 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."

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 a termination results in returning the capacity back into the § 399.20 FiT Program. SCE also requests the Commission clarify whether termination results in the need for additional contracts under the § 399.20 Program or can the capacity be replaced with 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 termination provisions narrowly by limiting the application of termination rights to the two events described in subsection (l)(1) and (l)(2). [70] 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 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 on-going 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 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.

21. 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 directing parties to rely on the existing provisions of Tariff Rule 21 until the Commission finalizes its on-going

[70] § 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.

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 Tariff Rule 21 or the FERC interconnection procedures under the Wholesale Distribution Access Tariff (referred to as "WDAT"). 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.11-09-009.

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 generate 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.[71] 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 obligations. SCE points to WDAT as a possible alternative process. We agree

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

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 take a year or longer and recommends reliance of Rule 21 as an accessible means of addressing interconnection as 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 on expedited interconnection, 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.

22. Refunds of Other Incentives

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 comments.

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 when 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 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 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.

23. FERC Certification of Generator for Qualifying Facility Status

Since this program is developed to be compliant with PURPA, a participating generator must register with FERC as a QF. Generators may utilize FERC's self-certification[72] process by filling out FERC's Form 556. Generators

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72 FERC provides two certification options: self-certification or FERC certification.

can visit FERC's website for more information on how to self-certify as a qualifying facility.[73]

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

The Joint Parties filed a motion[74] 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. 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."[75] 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.

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

[74] *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.

[75] *Id*. at 5.

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 pro and cons of the Staff Proposal as compared to various alternative-pricing proposals.

The motion is denied.

24.1. 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. Solutions for Utilities seeks specific changes to the mechanics of § 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, on-going Commission rulemaking on Rule 21 interconnection matters, R.11-09-011.

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 Clean Coalition's petition for modification.[76] 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.

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[76] *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*)

Therefore, because all this 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.

25. 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 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, on-going 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.

26. 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 ________, and reply comments were filed on _______ by _____________.

27. 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 a natural gas-fired electric plant, and not a renewable generator. The MPR reflects the costs of a different energy market, 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 very different market represented by 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 *ratepayer* 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 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 monthly market 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 only increase or decrease if there is sufficient market interest in a product type, but the price is either too low or too high as determined by how many projects execute contracts at a particular monthly Re-MAT price.

16. 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.

17. Reallocating capacity between the product types after the expiration of 12 program months will prevent gaming, minimize ratepayer exposure to excessively high contract prices, and efficiently manage allocated unused capacity.

18. 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.

19. To ensure ratepayer indifference under § 399.20(d)(3), a market-based approach to pricing is in the best interest of California electricity customers.

20. Section 399.20(f) restricts the Commission from creating program requirements that interfere with the first-come-first-served requirement as it applies to the program as a whole but also permits consideration of a limited type of pricing elements.

21. In the absence of any specific legislative directive, a Commission requirement that pricing be distinguished based on technology-specific basis would interfere with the application of the statutory provisions requiring first-come-first-served.

22. The statute allows for first-come-first-served on a product specific basis as it specifically directs the Commission to consider the value of different electricity products including baseload, peaking, and as-available electricity in § 399.20(d).

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

24. 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.

25. 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.

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

27. 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.

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

29. The plain language of the statute 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 costs of administering this program for the smaller utilities outweighs any potential benefit from their contribution of approximately 3 MW to the overall program.

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

31. 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.

32. No statutory provision requires us to consider a set aside and a set aside program for a particular technology is inconsistent with the requirement that the program be made available on a first-come-first-served basis.

33. PG&E, SCE, and SDG&E maintain two tariff schedules under 399.20 which are similar in many respects and, in the interest of administrative efficiency, no justification exits to retain two separate schedules.

34. 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.

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

36. 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.

37. 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.

38. 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.

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

40. 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.

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

42. 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 and to comply.

43. 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.

44. 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, on-going Commission rulemaking on Rule 21 interconnection matters, R.11-09-011.

45. The issues framed by Sustainable Conservation's petition for modification are addressed in today's decision or will be addressed in the separate, on-going 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, 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 costs 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 as long as state law has imposed an obligation on the utility to purchase energy from those sources of energy.

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 is 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 320, 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 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 320, 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 on-going 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, and not ratepayer or utility costs, which might be argued to be inconsistent with federal requirements under PURPA.

14. Because technology specific adders are largely based on general avoided societal costs, and not ratepayer 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 neither directs nor suggests 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 DALP 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 distributed 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 monthly price adjustment mechanism for each product type should be adopted. The monthly price may increase or decrease from the prior month's price by increasing or decreasing amounts, depending on the subscription results in each product type for each utility.

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

27. Utilities should incrementally release a portion of their total program capacity allocation each month for a 12-month period.

28. Utilities should be allowed to reassign capacity between the product types after the expiration of 12 program months to prevent gaming, minimize ratepayer exposure to excessively high contract prices, and efficiently manage allocated unsubscribed capacity.

29. 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.

30. 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 ensures ratepayer indifference under § 399.20(d)(3).

31. Re-MAT, which includes consideration of product types but not specific technologies, is consistent with the first-come-first-served provision set forth in § 399.20(f) because the statute permits consideration of product types.

32. Increasing the maximum project size to 3 MW is reasonable based on the Commission's obligation to implement to provisions of the statute and the absence of any identified reliability concerns.

33. 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.

34. 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.

35. 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, in addition, must be sited near load, meaning not in an area with such low load that interconnection of the proposed generation would require utilization of the transmission system and new transmission infrastructure.

36. 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.

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

38. 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.

39. 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.

40. No set-aside (or carve-out) of capacity for specific technologies should be adopted because § 399.20 applies equally to all electric generation facilities, regardless of technology, and must be made available on a first-come-first-served basis under § 399.20(f).

41. 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.

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

43. The FiT Program should not exclude excess sales.

44. 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.

45. 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.

46. 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.

47. 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.

48. This decision implements SB 32 pertaining to expedited interconnection by directing parties to rely on the existing provisions of Tariff Rule 21 (rather than those under review) until the Commission finalizes its on-going 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 allow generators to choose which interconnection processes to use, either the process set forth in the Tariff Rule 21 or the FERC interconnection procedures, the Wholesale Distribution Access Tariff.

49. 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 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.

50. 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.

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

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

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

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 monthly Feed-in Tariff price and available capacity, including any result from the price adjustment

mechanism or the capacity reassignment methodology, publicly available on their websites by the first business day of each month.

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 monthly pricing adjustment mechanism. To the extent that changes to the monthly price adjustment mechanism are needed to improve the program, PG&E, SCE, and SDG&E are permitted to file a joint Advice Letter seeking specific changes to the mechanism.

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 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 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 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 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 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 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 not in an area with such low load that interconnection of the proposed generation would require utilization of the transmission system and new transmission infrastructure or transmission system network upgrades. Such a provision shall be presented to the Commission for consideration in accordance with the schedule set forth in 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 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 contract provisions to reflect the consolidation of tariffs applicable to public water or wastewater agencies and tariffs for other customer into 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 the provision. 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 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 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 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 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 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.

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 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. 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.

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

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

21. Rulemaking 11-05-005 remains open.

The order is effective today.

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			