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BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

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

ADMINISTRATIVE LAW JUDGE'S RULING SETTING FORTH IMPLEMENTATION PROPOSAL FOR SB 32 and SB 2 1X AMENDMENTS TO SECTION 399.20

In Order Instituting Rulemaking (R.) 11-05-005 issued on May 10, 2011, the Commission identified the need to implement the recent amendments to Pub. Util. Code § 399.20[1] set forth in Senate Bill (SB) 32 (Negrete McLeod, Stat. 2009, ch. 328, § 3.5) and the pending amendments set forth in SB 2 of the 2011-2012 First Extraordinary Session (SB 2 1X) (Simitian, Stats. 2011, ch. 1.) Today's ruling sets forth an initial proposal for implementing these amendments with the intention of moving forward expeditiously on this matter. Other issues identified in R.11-05-005 will proceed on a separate track.

This initial proposal on implementation of SB 32 and SB 2 1X will serve as a starting point for further comments by parties. Parties are requested to file comment on this initial proposal on or before July 21, 2011 and reply comments may be filed on or before July 28, 2011. A prehearing conference will be scheduled on July 11, 2011. The purpose of the prehearing conference will be to

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

discuss this proposal for implementing SB 32 and SB 2 1X. A workshop on pricing issues is tentatively scheduled for August 31, 2011 and September 1, 2011. The times and location of this workshop will be announced after a final determination is made that the workshop is needed.

The goal is to present the Commission with a proposed decision on this matter toward the end of 2011. To meet this goal, parties need to specifically identify those aspects of SB 32 and SB 2 1X that must be addressed or could be addressed without delaying this timeline. Parties must also specifically identify any remaining issues that the Commission could postpone consideration of and present an expeditious timeline for consideration of these remaining issues to begin in 2012. This topic will be discussed at the prehearing conference.

1. Background

On March 7, 2011 and March 22, 2011, parties submitted briefs in R.08-08-009 to provide the Commission with guidance on the implementation of SB 32. The current proceeding, R.11-05-005, succeeds R.08-08-009 and incorporates the entire record of R.08-08-009, including these March 2011 briefs. I have reviewed the briefs and the information provided forms the basis for the proposal set forth in this ruling. However, due to recent actions by the Legislature, specifically, the passage of SB 2 1X, more information is needed prior to the Commission's full implementation of § 399.20.

When SB 2 1X becomes effective 90 days after the end of the Legislature's 2011-2012 First Extraordinary Session, the new legislation will amend the provisions of § 399.20(d) pertaining to price. Pricing is a critical component of implementing § 399.20. The SB 2 1X amendments are set forth below. New statutory language is identified with italics and the deleted language is identified in strikeout.

> (d) (1) The tariff shall provide for payment for every kilowatt hour of electricity purchased from an electric generation facility for a period of 10, 15, or 20 years, as authorized by the commission. The payment shall be the market price determined by the commission pursuant to ~~Section 399.15~~ *paragraph (2)* and shall include all current and anticipated environmental compliance costs, including, but not limited to, mitigation of emissions of greenhouse gases and air pollution offsets associated with the operation of new generating facilities in the local air pollution control or air quality management district where the electric generation facility is located. *(2) The commission shall establish a methodology to determine the market price of electricity for terms corresponding to the length of contracts with an electric generation facility, in consideration of the following: (A) The long-term market price of electricity for fixed price contracts, determined pursuant to an electrical corporation's general procurement activities as authorized by the commission. (B) The long-term ownership, operating, and fixed-price fuel costs associated with fixed-price electricity from new generating facilities. (C) The value of different electricity products including baseload, peaking, and as-available electricity. (3) The commission may adjust the payment rate to reflect the value of every kilowatt hour of electricity generated on a time-of-delivery basis. (4) The commission shall ensure, with respect to rates and charges, that ratepayers that do not receive service pursuant to the tariff are indifferent to whether a ratepayer with an electric generation facility receives service pursuant to the tariff.*

The SB 2 1X amendments to § 399.20 remove the reference to § 399.15 for determination of price and, as a result, the price for electricity purchased from an electric generation facility under § 399.20 is no longer tied to the cost containment provision of the renewables portfolio standard.[2] By removing the

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[2] SB 2 1X will eliminate the current cost containment provision in § 399.15, which required the Commission to establish a total cost limitation for contracts with prices above a market price. Once the cost limitation is exhausted, the Commission can not require privately owned utilities to sign RPS contracts above the market price. The

Footnote continued on next page

connection between the pricing provisions of § 399.20 and § 399.15, the range of outcomes of an independent pricing analysis under § 399.20 potentially increases. Previously, the pricing for electric generation under § 399.20 was tied to the Market Price Referent per D.07-07-027.[3] With the amendments set forth in SB 2 1X, this connection to the Market Price Referent no longer must apply. In addition, as shown in the above quoted excerpt, SB 2 1X adds pricing provisions into § 399.20 to apply to electric generation facilities. We are familiar with the language of these pricing provisions added to § 399.20 because the new provisions are identical to those previously included in § 399.20 through the now-deleted reference to § 399.15.

2. Implementation Goals

The Commission's goal is to address implementation of the amendments to § 399.20 in SB 32 and SB 2 1X on an expeditious schedule. I intend to establish a schedule that provides for full implementation, if possible, or partial implementation by the end of 2011. Parties should comment on this goal.

Commission defined market price in D.03-06-071 and D.04-06-015 to be the Market Price Referent or MPR.

[3] Details of the MPR calculation: When adopting the MPR for the RPS cost containment mechanism, the CPUC determined that the MPR should reflect the long-term ownership, operating, and fixed-price fuel costs for a new 500 MW natural gas-fired combined cycle gas turbine. The MPR model calculates a levelized price for a proxy baseload gas-fired combined cycle gas turbine using a cash flow modeling approach. The inputs for the MPR model include installed capital costs, fixed and variable operations and maintenance costs, natural gas fuel costs, cost of capital, and environmental permitting and compliance costs. The model produces several MPR values based on a facility's online date and contract term length (i.e., 10, 15 or 20 years). 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 utilities' time-of-delivery factors.

Specifically, parties should comment on the goal of implementing the following aspects of SB 32 and SB 2 1X before the end of 2011: determine price, eliminate separate tariffs, eliminate retail customer requirement, increase facility size to 3 MW, adjust program cap to 750 MW, the 10-day internet posting requirement for new tariff requests, the exemption for small electric utilities, and coordination with publicly owned utilities. Under this proposal, we would address the remaining issues in early 2012. These issues would include the yearly inspection and maintenance reports required by § 399.20(p), denial of tariff requests set forth in § 399.20(n), contract termination provisions set forth in § 399.20(l), the expedited interconnection process set forth in § 399.20(e), and refunds of other incentives set forth in § 399.20(k).

The goals for implementing the new aspects of this program include market stability, regulatory certainty, increased transparency, complying with related federal law, administrative ease, cost containment, incorporating environmental benefits, reducing transaction costs for sellers, buyers and regulatory agencies and, to the greatest extent possible, harmonizing the Commission's § 399.20 program with other existing programs, such as the Renewable Auction Mechanism set forth in D.10-12-048, the Commission's Combined Heat and Power program under Assembly Bill (AB) 1613, and the net-metering program under § 2827.

3. Compliance with SB 2 1X

As discussed above, SB 2 1X will incorporate new language into § 399.20 pertaining to pricing for the electricity purchased from an electric generation facility. Today's ruling requests comments on whether the Commission should reevaluate the options to determine the market price as a result of the amendments set forth in SB 2 1X. All comments must include specific calculations and formulas needed for the Commission to implement a new price proposal.

In the most basic terms, the amendments provided for in SB 2 1X can be reduced to the following rudimentary formula:

Eight mandatory considerations for calculating the price, as follows:

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

(2) Long-term market price for fixed price contracts
§ 399.20(d)(2)(A);

(3) Long term operating and 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) Ratepayer indifference
§ 399.20(d)(4);

(7) 10, 15, and 20 year contract terms
§ 399.20(d)(1);

(8) All current and anticipated environmental compliance costs
§ 399.20(d)(1);

and two optional inputs, as follows:

(9) Time of Delivery
(§ 399.20(d)(3)); and

(10) Locational Distribution Circuit adder
§ 399.20(e).

In the discussion that follows, the ruling sets forth potential pricing options based on the March 2011 briefs and also considers the additional amendments set forth in SB 2 1X. This ruling anticipates that the Commission will address pricing by the end of 2011.

3.1. Definition of Market Price

In order to establish the methodology for determining the feed-in tariff price, it is necessary to first define market price of electricity. Section 399.20(d)(2) states "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…."

1) Please respond in comments to the following questions: Define market price of electricity as used in § 399.20. Is there one market price of electricity relevant to all types of electricity procurement or are there different market prices depending on the type of electricity that is being procured? For example, is there a unique market price of electricity for the market segment targeted in § 399.20? Does the market price of electricity include all types of electricity contracts and technologies that a utility procures or a subset of contracts and technologies? If you propose a subset, please define the subset.

3.2. Continued Reliance on Market Price Referent

In March 2011 briefs, some parties supported the continued use of the MPR as the basis for the electric generation facility rate. Parties supporting the use of the MPR include the California Solar Energy Industry Association, Clean Coalition, the Division of Ratepayer Advocates, Silverado Power, Center for Energy and Efficiency and Renewable Technologies, The Utility Ratepayer Network and others. These parties had various proposals on how to use the MPR and whether they supported any modifications or new adders. While Pacific Gas and Electric Company (PG&E) and San Diego Gas & Electric Company (SDG&E) question the legality of the rate, they support voluntary reliance on the MPR. Other parties, such as FuelCell Energy, took the position in the March 2011 briefs that the electric generation facility's rate does not need to be based on the MPR.

Please respond in comments to the following questions:

2) Explain whether the price for electricity purchased under § 399.20(d), as amended by SB 2 1X, must or should be based on the MPR as currently calculated.

3) Explain whether the price for electricity purchased under § 399.20(d) must or should be based on the MPR as currently calculated with the addition of new adders, as suggested by parties in the March 2011 briefs.

4) Explain the benefits and the drawbacks of continuing to use the MPR as the basis of the price for the program under § 399.20 given the statutory changes.

5) Under the current RPS program rules each annual RPS Solicitation triggers an update to the MPR values.[4] Consistent with CPUC decisions, Energy Division staff will calculate a 2011 MPR for the 2011 RPS Solicitation. Due to the statutory changes in SB 2 1X, it is not clear whether the Commission will continue to calculate an MPR to establish an RPS cost limitation. Parties should explain whether a new trigger for an MPR update is necessary and/or a schedule for how the MPR should be updated going forward.

3.3. Additional Pricing Proposals

In March 2011 briefs, parties provided other proposals for a price calculation under § 399.20. These other proposals included a (1) technology-specific rate and product-specific rate, (2) market-based rate and (3)

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[4] See D.04-06-015 and D.08-10-026.

rate based on power purchase agreements. These proposals are briefly described below. Additional comments from parties are sought on these proposals.

When responding to the proposals below, explain whether a separate numerical value should be calculated for environmental benefits and/or locational benefits and added to the market price, or whether these items should be reflected in a single market price. If adders are incorporated as part of a recommended method for price calculation, provide specific comments on the approaches suggested in the March 2011 briefs, such as those offered by CALSEIA, the Solar Alliance and the Vote Solar Initiative.

3.3.1. Technology-Specific Rates and Product-Specific Rates

In the March 2011 briefs, some parties, such as, the Agricultural Energy Consumers Association and the Inland Empire Utilities Agency, California Wastewater Climate Change Group, and FuelCell Energy recommended technology-specific rates for different types of renewable resources. Parties also suggested product-specific rates. Product-specific rates would include rates for each type of renewable product, such as, firm, non-firm peaking, and non-firm non-peaking, as defined in D.10-12-048.

Please respond in comments to the following questions:

6) Based on your definition of "market price of electricity," explain whether a technology-specific or product-specific proposal is a viable option for the § 399.20 program as updated by the SB 2 1X amendments.
7) Explain the specific methodology and all calculations and data that would be required to implement the technology or product-specific rate that you propose.
8) If applicable, identify what specific subset of proxy plants is appropriate for the calculation. An example of a Commission-adopted methodology for calculating

technology-specific costs would be the MPR model, which calculates the proxy costs of building and operating a Combined Cycle Gas Turbine (CCGT) facility.

3.3.2. Market-Based Rate

In March 2011 briefs, Southern California Edison Company (SCE) suggested that price under § 399.20 be determined by competitive auction.

Please respond in comments to the following questions:

9) Do you support this approach? Please explain. Discuss whether and how this approach is consistent with the provisions in § 399.20(f). Also explain the mechanisms of how a competitive auction would be used to determine the price (e.g., are projects paid as bid, paid the market clearing price, or paid another price point determined through an auction), and how, if at all, the auction would differ from the design of the Renewable Auction Mechanism in D.10-12-048.

3.3.3. Rate Based on Power Purchase Agreements

When the Commission adopted the MPR in compliance with the then-existing provisions of § 399.15, some parties supported a market price based on the actual prices in power purchase agreements. At that time, the Commission did not adopt a market price based on prices found in power purchase agreements because, according to the Commission, the record did not "indicate that there are contracts sufficient in number or comparability to provide a basis for setting a market price." (D.03-06-071 at 16.)

Please respond in comments to the following questions:

10) Given that a significant number of RPS solicitations[5] have occurred since this time, using your definition of the market price of electricity, explain whether a rate under § 399.20(d) should be based on RPS power purchase agreement prices. Parties supporting this methodology should identify what subset of power purchase agreements is appropriate for the calculation, whether the price should be the weighted average of PPA prices or some other price point, and provide specific recommendations and calculations, where appropriate and necessary to implement such a methodology. Lastly, parties should articulate if there should be one rate or multiple rates. If parties suggest multiple rates, parties should define what the multiple rates should be and how they should be derived.

11) Provide all relevant details for other alternate pricing proposals, if any, consistent with the provisions of SB 2 1X.

3.4. Additional Pricing Questions

12) Identify relevant data sources that could be used to implement any proposed methodology and whether the data used to calculate the rate should be derived from public or confidential data. Please comment on the appropriateness of the data sources as identified by parties in opening comments, such as Fuel Cell Energy and CALSEIA.

13) Explain how often the price under § 399.20(d) should be calculated given your preferred price calculation approach. The price may be calculated once, at regular intervals, such as annually, or in response to a triggering event. For example, in March 2011 briefs, CALSEIA proposed that the price be modified quarterly and be

[5] The RPS program has had several solicitations since the program began. In addition, PG&E and SCE have held one solicitation each for their Solar PV Programs.

> increased or decreased based on market participation. The California Solar Initiative presented a different model for reducing prices over time in which incentive rates decline over the life of the program in multiple steps triggered by solar capacity additions to facilitate market transformation.[6]

3.5. Ratepayer Indifference

In March 2011 briefs, parties addressed the requirement 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," (§ 399.20(d)(3)). Some, including CEERT, stated that ratepayers are indifferent to any avoided cost rate and others found ratepayer indifferent to any rate that is value based. These parties included, among others, CALSEIA and Clean Coalition. Clean Coalition also cited the Commission's application of a customer indifference provision in the implementation of AB 1613.[7]

Please respond in comments to the following questions:

14) Respond to these interpretations of "ratepayer indifference" and explain how the SB 2 1X amendments to § 399.20(d) and any new pricing proposal that you suggest pursuant to these amendments impact these interpretations.

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[6] For a description of the California Solar Initiative incentive adjustment mechanism, see Section IV of D.06-08-028 at http://docs.cpuc.ca.gov/word_pdf/FINAL_DECISION/59186.pdf.

[7] "In light of these considerations, we find that customer indifference under AB 1613 would not be achieved if the price paid under the program only reflected the market price of power. As discussed, since customers who are not utilizing the eligible Combined Heat and Power (CHP) 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.)

3.6. FERC Order 134 FERC ¶ 61,044 - Order Denying Rehearing

With the statutory amendments set forth in SB 2 1X, parties are provided with an opportunity to offer additional comments on the impact of federal law on the implementation of § 399.20. It is not necessary to reiterate the positions set forth in the March 2011 briefs.

15) Please indicate how those positions have changed, if at all.

4. Compliance with SB 32

The provisions added to § 399.20 by SB 32 are set forth below. This ruling identifies those provisions that we propose be implemented by the end of 2011 and those provisions that will be addressed in 2012.

16) Parties are requested to comment on this proposal.

4.1. Increase Size of 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. SB 32 increased it to 3 MW. SB 2 1X makes no change to this provision. Section 399.20(j)(2), which was added by SB 32, provides the Commission with the authority to reduce the 3 MW capacity limitation if necessary to maintain system reliability.

This ruling proposes to implement the 3 MW provision by end of 2011.

17) Explain any further issues to be considered on capacity limitation under this program and next steps necessary to implement the provision. To implement § 399.20(b)(2), tariff language and form contracts may need to be amended. The investor owned utilities should submit tariff changes or revised contract language, if any, to implement this change with comments on July 21, 2011 and July 28, 2011.

4.2. Proportionate Share and Increased Program Cap to 750 MW

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 the code section. The total amount subject to § 399.20(e), as originally implemented, was 250 MW. This amount was later increased to 500 MW by SB 380. SB 32 modified this language by increasing the total megawatts subject to the code section from 500 to 750 MW. SB 32 also renamed the relevant subsection from subsection (e) to subsection (f) and included local publicly owned utilities within the calculation of proportionate share. SB 2 1X made no further modifications to this particular language. In the interest of administrative ease, it is reasonable to maintain the current allocation methodology.

This ruling proposes to implement this provision by end of 2011.

18) Explain the drawbacks and benefits to relying on the existing methodology for calculation of proportionate share. Does the statute require a recalculation of proportionate share based on the addition of publicly owned utilities? Would the Commission's calculation of proportionate share for local publicly owned utilities be restricted by any jurisdictional limitations?

4.3. Separate Tariffs

Section 399.20(b), as originally enacted by AB 1969, contained the requirement that "electric generation facilities" as defined therein, be owned and operated by a public water or wastewater agency. In D.07-07-027, the Commission found it reasonable to establish a program equivalent to the program established by § 399.20 to include other customers as well. In implementing both § 399.20 and D.07-07-027, the Commission directed electric corporations to file two tariff schedules, one schedule for public water or wastewater agency and a separate schedule for all other customers. Each electric corporation, regardless of size, currently has these two tariff schedules. In 2009, § 399.20(b) was amended by SB 380 to remove 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:" (The additional criteria are omitted and not relevant for purposes of this discussion.)

Based on the language of § 399.20, it appears reasonable to direct electric corporations to consolidate the two rates schedules. Consolidation of tariffs may decrease transaction costs by simplifying the administration of the program.

19) This ruling proposes to implement this provision by end of 2011. Explain the next steps necessary to implement this request.

4.4. Retail Customer Requirement Eliminated

As enacted by AB 1969, § 399.20(b) required the electric generation facility be, among other things, "owned and operated by a retail customer" of an electrical corporation. SB 32 removed this requirement and inserted the language "located within the service territory of, and developed to sell electricity to…." SB 2 1X retains this modification. As a result, § 399.20 apply to those that are not retail customers of the electrical corporation and also to those that are not owners or operators of the electric generation facility.

This ruling proposes that the Commission implement this provision by end of 2011.

20) Explain the next steps necessary to implement this provision, what modification to tariffs are needed to reflect this change, and what changes to the form contract might be required.

4.5. Yearly Inspection and Maintenance Report

SB 32 added the requirement to § 399.20 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." This requirement was added at subsection (p) of § 399.20. SB 2 1X did not modify this requirement.

This ruling proposes that the Commission not implement this provision by end of 2011 and, to instead, address this matter at the beginning of 2012.

21) Parties are asked to comment on this recommendation.

4.6. 10-day Reporting Requirement of Request for Service under Tariff:

SB 32 added subsection (m) to § 399.20. SB 2 1X did not modify subsection (m). Subsection (m) requires 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, in addition, (2) the name of city where facility is located. Subsection (m) specifically 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.

This ruling proposes to implement this provision by end of 2011.

22) Parties are asked to comment on this recommendation.

This implementation will primarily rely on the reporting format that the Commission already requires, with the specific changes to reflect SB 32. This information is: Project Name, Status (e.g., Operational, delayed), Capacity (MW), Expected GWh/yr, Technology, Price ($/MWh), Vintage (e.g., existing, new), Term (years), Location (City), Contract Execution Date, Online Date/Contracted Delivery Date, and Achievement of the Commercial Delivery Date with 18 months (yes or no).

This ruling also anticipates by the end of 2011 clarifying, as requested by PG&E, whether the compliance period is 10 business days or 10 calendar days. PG&E also requested the Commission explain the event which starts the counting of this 10 day compliance period. This too will be address within 2011.

4.7. Publicly owned electric utilities

SB 32 added § 387.6 to the Public Utilities Code. Section 387.6 requires a local publicly owned electric utility to offer a tariff to owners or operators of electric generation facilities within its service territory. It is reasonable to anticipate that certain issues to be resolved in implementing SB 32 and SB 2 1X for investor owned utilities may benefit from coordination with local publicly owned electric utilities.

This ruling anticipates addressing these issues by the end of 2011.

23) Identify any issues and explain why coordination would be helpful. Identify any potential matters that the Commission may address relative to § 399.20 that may impact the implementation of § 387.6. One issue already identified in March 2011 briefs is the calculation of proportionate share of the 750 MW program cap.

4.8. Utility Discretion to Deny Tariff

SB 32 added subsection (n) to § 399.20 to provide an electric corporation the ability to deny a tariff request by an electric generation facility in certain circumstances relating, generally, to compliance with the statute and ensuring the safety of the electric grid. In its March 2011 opening brief, FuelCell Energy suggested that the Commission clarify this provision to avoid unnecessary misunderstandings and disputes. Specifically, FuelCell Energy requested that the Commission determine the point in the contracting process that a utility may deny such a tariff request. Others, including the Solar Alliance and the Vote Solar Initiative support further clarification but did not 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.

This ruling proposes to not implement this provision by end of 2011. This issue will be addressed at the beginning of 2012.

24) Parties are asked to comment on this recommendation. Also, explain the existing procedure relied upon by electric utilities to deny tariff requests.

4.9. Tariff or Contract Termination Provisions

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

This ruling proposes to not implement this provision by end of 2011. This issue will be addressed at the beginning of 2012.

25) Parties are asked to comment on this recommendation. Also, explain the existing procedure relied upon by electric utilities to terminate contracts.

4.10. Expedited Interconnection Procedures

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. (D.07-07-027 at 40.)

This ruling proposes to not implement this provision by end of 2011. This issue will be addressed at the beginning of 2012.

26) Parties are asked to comment on this recommendation.

4.11. Adjustments for Small Electric Utilities

SB 380 amended § 399.20 to add subsection (h), which authorized the Commission to modify or adjust the applicability of § 399.20 for any electric corporation with less than 100,000 service connections, as individual circumstance merit. SB 32 moved this provision to subsection (c) but left the language essentially unchanged.

The March 2011 brief by the California Association of Small and Multi-Jurisdictional Utilities (CASMU)[8] requests that the Commission rely on the statutory provisions of § 399.20(c) to exempt electric corporations with less than 100,000 service connections from the requirements of § 399.20. The members of

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[8] CASMU includes Bear Valley Electric Service, a division of Golden State Water Company, California Pacific Electric Company, LLC dba Liberty Energy, California Pacific Electric Company, Mountain Utilities, and PacifiCorp dba Pacific Power.

CASMU operate with between approximately 700 and 46,000 service connections. CASMU also pointed out that, in addition to service connection numbers, its members differ significantly from the three largest electric corporations, PG&E, SCE and SDG&E. It further pointed out that the combined obligation of all CASMU members under § 399.20 as implemented by D.07-07-027 was 0.599%.

Other parties, such as CALSEIA and Sustainable Conservation, suggested that participation by small electric corporations be voluntary but also noted that such participation is an important component of the State's 33% renewable goal. The three largest electric corporations did not present a unanimous position. PG&E did not comment on this provision. SCE stated that the smaller electric corporations are legally required to participate because the exemption in subsection (c) is for just parts of the program, not the whole program.

SCE's legal interpretation is not persuasive. The plain language of the statute suggests otherwise. Based on the goals of administrative ease, reducing costs of implementation, an exemption from the program for all electrical corporations with less than 100,000 service connections appears reasonable. This recommendation would represent a modification to D.07-07-027.

This ruling anticipates addressing these issues by the end of 2011.

27) Parties are asked to comment on this recommendation.

4.12. 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 or the Small Generator Incentive Program.

This ruling proposes not to implement this provision by end of 2011. This issue will be addressed at the beginning of 2012.

28) Parties are asked to comment on this recommendation.

5. Administrative Issues

To assist with the efficient administration of the § 399.20 portion of this proceeding, parties are requested to:

- Designate the subject line of all emails as "R11-05-005 Sec. 399.20 program."
- The pleading title for all comments in response to this ruling should be as follows: Party Name [Reply] Comments to Sec. 399.20 Ruling [date of ruling].
- Identify the party name at the bottom of each page of all filings.
- Include a table of contents with all filings.
- I will not be sending out paper copies of documents or notices of availability if the party has an email contact on the service list. Please contact me with concerns regarding this service policy.
- All copies of documents submitted to the Commission should be double-sided copies.

IT IS RULED that a prehearing conference shall be held in this matter on July 11, 2011. Initial comments shall be filed on or before July 21, 2011. Reply comments shall be filed on or before July 28, 2011. A workshop is tentatively scheduled for August 31, 2011 and September 1, 2011.

Dated June 27, 2011, at San Francisco, California.

Burton W. Mattson for

Regina DeAngelis
Administrative Law Judge