BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Promote Policy and Program Coordination and Integration in Electric Utility Resource Planning.	Rulemaking 04-04-003 (Filed April 1, 2004)

OPENING TESTIMONY OF EDWARD W. TOMEO ON BEHALF OF THE RENEWABLES COALITION

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Order Instituting Rulemaking to Promote Consistency in Methodology and Input Assumptions in Commission Applications of Short-run and Long-run Avoided Costs, Including Pricing for Qualifying Facilities.	Rulemaking 04-04-025 (Filed April 22, 2004)

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I. INTRODUCTION

Q: Please state for the record your name, position, and business address.

A: My name is Edward W. Tomeo. I am the founder of Enpower Corp., which is an energy-facility owner and highly skilled business and operations management company to energy and process industries. I am also President and Chief Executive Officer of Enpower Corp.'s business and operations management company, Enpower Management Corp. My business address is 2420 Camino Ramon, Suite 101, San Ramon, California 94583.

Q: Please describe your experience and qualifications.

A: I have almost 30 years of experience in process and electric power generation businesses, with much of my experience focusing on the renewable energy market. Prior to my involvement with Enpower Corp., I was a Vice President of United American Energy Corp. ("UAE") and President of UAE's western operations subsidiary, UAE Energy Operations Corp. ("UAEEOC"). I founded UAEEOC in 1993 to manage the operations of two distressed projects that were acquired by UAE. UAEEOC managed the successful business recovery of the Modesto Energy waste-tire-fired facility and the Wadham Energy rice hull-to-energy facility. In 1996, I led the acquisition of the 40-megawatt ("MW") Oildale Energy cogeneration facility. Starting with UAE in 1988, I was a leader in UAE's diversification into fossil fuel fired electric production.

Prior to UAE, I held management positions with Northeast Utilities, General Electric Environmental Services and Bethlehem Steel. I earned my BS in Mechanical Engineering from the University of Pennsylvania and an MBA from Rensselaer Polytechnic Institute and I am a registered professional engineer.

Q: On whose behalf are you testifying today?

A: I am appearing on behalf of the California Biomass Energy Alliance, L.L.C. ("CBEA"),[1] the California Landfill Gas Coalition ("CLGC")[2] and the California Wind Energy Association ("CalWEA")[3] (jointly, the "Renewables Coalition"). The Renewables Coalition represents a broad cross-section of the renewables community, including biomass, wind, solar-thermal and landfill-gas generating technologies and accounts for roughly 1,034 MW of existing renewable generating capacity in California. The energy associated with this capacity is a substantial part of the investor owned utilities' ("IOUs") baselines for compliance with the California Renewables Portfolio Standard ("RPS") program. Plants owned by members of the Renewables Coalition are qualifying facilities ("QFs") under the Public Utility Regulatory Policies Act of 1978 ("PURPA") and hold either power purchase agreements or standard offer contracts with the IOUs. As a result, the Renewables Coalition has a strong interest in the outcome of this proceeding, which will affect how, if at all, renewable facilities that are QFs will be able to continue to provide renewable power to Californians.

Q: Please summarize the recommendations that you present in this testimony.

A: My testimony recommends the following:

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[1] The CBEA is a formal trade organization representing 27 of the 28 operating biomass power plants in California, as well as a number of the currently idle biomass plants. The CBEA plants are primarily located in rural areas of 19 different California counties, and provide power to all three of the State's major IOUs. Twenty of the 28 CBEA plants are operating under the current five-year fixed price amendments. In aggregate, CBEA members' operating QF projects in California provide 570 MW to the IOUs.

[2] The members of CLGC construct, operate, and maintain facilities to collect landfill gas and produce clean, renewable electricity. The CLGC consists of a majority of the 42 landfill-gas facilities in California that are renewable QFs and are operating under the current five-year fixed price agreements with the IOUs. CLGC members generate approximately 264 MW of environmentally sound and cost-effective energy.

[3] CalWEA is comprised of wind energy generators, project developers and various wind generator service providers. Many CalWEA members own and operate QF projects that sell electricity to the IOUs under existing standard offer contracts at avoided cost rates. In the aggregate, CalWEA member projects in California sell 200 MW to the IOUs.

- **The Commission should establish a renewed five-year fixed-price option for QFs upon expiration of the current five-year energy pricing amendments.** The energy crisis demonstrated that a fixed energy price brings significant stability to the contractual relationships between the IOUs and QFs, which encourages investment in existing facilities. Meanwhile, fixed prices guard ratepayers against market-price volatility and maximize the use of existing renewable resources, which aligns with the goals of the RPS program.

- **The Commission should update current as-available and as-delivered capacity prices.** The disparity between the IOUs' avoided cost prices for as available capacity demonstrates that many QFs are not receiving full avoided cost payments for their capacity. In particular, this is a problem in the service territory of Southern California Edison Company ("Edison"). This disparity should be reviewed and corrected in order to ensure that existing QFs remain online, thus helping the IOUs to achieve their RPS-program targets. Further, this update is necessary in order to ensure that prices for as-available capacity sales by QFs comply with PURPA's requirement that QFs receive full avoided cost payments for sales of energy and capacity.

- **The Commission should adopt long-term contracts for QFs whose contracts expire and for new QFs.** Specifically, the Commission should adopt both a long-term firm capacity contract and a long-term as-available capacity contract for QFs whose contracts expire and for new QFs. The firm capacity contract should be available to new renewable QFs in each IOU's service territory at least until the IOU has met its RPS program target. The as-available capacity contract should be based upon the current Standard Offer 1 ("SO1") contracts. Long-term contracts are needed to keep the existing stock of QFs on-line, to encourage existing QFs to upgrade their facilities and to support investment in new QF generation sources. Long-term QF contracts are needed as a complement to the RPS program solicitations, which short-change existing renewable QFs. Long-term contracts are also needed in order to ensure that California continues to comply with PURPA's must-purchase obligation.

- **The Commission should require the IOUs to apply existing QFs' interconnection arrangements to their new long-term contracts.** As the Federal Energy Regulatory Commission ("FERC") has explained in a series of recent orders regarding the standardization of interconnection procedures, existing interconnection arrangements have already been reviewed for possible impacts upon the safety and reliability of the interconnected IOU's transmission system and therefore new review is unnecessary and inappropriate unless the interconnected QF's operations have changed substantially. The same rule should be employed in California for Commission-regulated interconnections. Moreover, existing QFs with existing interconnection arrangements should not have to pay for any capital-related costs for facilities upon extending their interconnection arrangements because such capital costs have already been fully amortized.

Q: How does your opening testimony address the subjects contained in the outline for opening testimony jointly adopted by the parties in this proceeding?

A: This testimony responds to three subjects contained in the outline for opening testimony jointly adopted by the parties. Specifically, this testimony presents the proposals of the Renewables Coalition to (1) update the prices paid by the IOUs for as-available capacity sold by QFs (item V.B.4 of the Joint Outline submitted by the Cogeneration Association of California, the Energy Producers and Users Coalition, the Indicated Energy Producers and the California Cogeneration Council (the "Joint Outline")); (2) offer a renewed five-year fixed-price option to QFs with existing contracts (item IV.B.3 of the Joint Outline); and (3) adopt both long-term firm capacity and as-available capacity contracts for both new and existing QFs (item V.E of the Joint Outline). This testimony employs the relevant headings below and does not refer to the Joint Outline's items that I do not address.

IV.B.2 THE COMMISSION SHOULD UPDATE AS-AVAILABLE CAPACITY PRICES.

Q: Should the Commission review and update the IOUs' as-available capacity prices?

A: Yes. As-available capacity prices have not been updated for many years and a significant disparity exists between the as-available capacity prices paid to QFs by the three IOUs. Although each of the IOUs' as-available capacity prices is currently derived from the costs of a combustion turbine ("CT"), the PG&E and SDG&E as-available capacity prices are $64.93 and $70.34 per kW/year, respectively, while Edison's as-available capacity price is only $4.93 per kW/year. Edison's as-available capacity price was established in 1996, when Edison had excess of capacity on its system. Edison's as-available capacity price has remained static since 1996 although the California Energy Commission has concluded that Southern California has insufficient resources to meet this summer's needs and that Edison no longer has excess capacity on its system as anticipated in 1996.[4] Edison also has an identified need for capacity to meet its recently adopted reserve targets and to serve load, as evidenced by Edison's recent capacity solicitations and its acquisition of the Mountainview power plant. Further, in light of the fact that CT costs have recently been updated for use in the RPS proceeding and that Edison itself has

[4] California Energy Commission Draft Report, "Summary 2005 Electrical Supply and Demand Outlook, March 2005, at Table 4.

proposed updated CT values in both its general rate case ($78 per kW/year) and in this proceeding ($83.50 per kW/year), it is reasonable to update the as-available capacity prices of each of the IOUs and Edison in particular.

Additionally, updating the IOUs' as-available capacity prices, in particular Edison's prices, is an important step to keeping QFs with long-term contracts that have expired or are set to expire in the near future from going offline. Unless the Commission updates Edison's as-available capacity prices, QFs in Edison's service territory that employ the reinstated SO1 contracts will receive only $4.93 per kW/year for capacity. This will under-compensate QFs and could result in QFs going offline. It certainly is not enough to encourage any major capital improvement, whether it is an efficiency upgrade, plant expansion or new construction. Given that Edison has not yet achieved the Commission's target of a 15 percent to 17 percent planning margin, and the risk of Edison facing slim reserve margins, it seems well-advised to update Edison's and the other IOUs' as-available capacity prices in order to keep existing QFs' capacity online and encourage development by new QFs.

Finally, updating the IOUs' as-available capacity prices is required by PURPA. Specifically, PURPA requires that utilities buy renewable power from QFs at an avoided-cost rate that accurately reflects the utilities' costs to generate or purchase capacity in the absence of QFs.[5] As discussed above, the IOUs' current QF prices for as-available capacity widely vary, and in the case of Edison, are significantly less than current avoided costs. Accordingly, in order to comply with PURPA, the prices should be reviewed and revised.

Q: What is your proposal for updated as-available capacity prices?

A: The Renewables Coalition supports the proposal of the California Cogeneration Council ("CCC") to update the IOUs' as-available capacity prices to equal the full cost of a CT, which R. Thomas Beach, the CCC's witness in this proceeding, calculates to be $110 per kW/year. This price should be escalated annually based upon changes in the Consumer Price Index to reflect the effect of inflation on CT costs. If, after the first full year following adoption of the new price, a party believes that the price should be revised, such party could petition the Commission to change the price.

[5] 18 C.F.R. § 292.304(b)(2); 18 C.F.R. § 292.304(e).

IV.B.3 THE COMMISSION SHOULD ADOPT A RENEWED FIVE-YEAR, FIXED PRICE OPTION FOR QFS WITH EXISTING CONTRACTS.

Q: Please explain why the Renewables Coalition recommends the adoption of a renewed five-year fixed-price option?

A: Adopting a renewed five-year fixed-price option for QFs with existing contracts that desire one will best respond to the Commission's concern "about the continued viability of QFs generally, QFs' contribution to the electric grid, and the economic and energy system effects when QFs cease operations."[6]

A renewed five-year fixed-price option is a method of stabilizing QF pricing and generation that was proven to be effective both during and after the 2000-2001 energy crisis. During the energy crisis, the Commission adopted, among other things, a *per-se* reasonable fixed energy price for QFs of 5.37 cents/kWh for a term of five years.[7] As the Commission stated, this option was designed "to help bring stability to the electricity supply contracts"[8] between QFs and utilities and to "ensure that QFs generate as much electricity as reasonably possible, and at reasonable prices."[9] The option was particularly beneficial because it "could provide ratepayers with significant near term savings compared to current prices, as well as protecting ratepayers against price volatility for the next five years."[10] This option was employed by numerous renewable and non-renewable QFs and by each of the utilities. Generally speaking, the five-year period began for PG&E QFs in July of 2001 and will end in June of 2006. For Edison and SDG&E QFs, the five-year period began in May of 2002 and will end in April of 2007.

As Table A (which was prepared by Crossborder Energy) demonstrates, the 5.37 cents/kWh fixed-price option has achieved the intended goals of the Commission. It has protected ratepayers against price volatility and has resulted in reasonable QF prices. In the service territories of each of the IOUs, the fixed-price option will likely result in significant savings to ratepayers as compared to weighted average of short run avoided cost ("SRAC")

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[6] D.02-09-047 at 5.
[7] D.01-06-015 at 4.
[8] D.01-09-021 at 3.
[9] D.01-06-015 at 3.
[10] *Id.* at 4.

prices during the relevant periods. Respectively, Edison, PG&E and SDG&E have saved 15%, 10% and 24% for the power they purchased from QFs during the relevant time periods under the fixed price amendments, compared to what they would have paid in SRAC prices.

Table A: SRAC versus Fixed QF Prices ($/MWh)

IOU	Five-Year Term	SRAC	Five-Year Fixed Price	Difference vs. SRAC	% Savings
Edison	May-02 to April-07	63.1	53.7	-9.4	-15%
PG&E	July-01 to June-06	59.4	53.7	-5.7	-10%
SDG&E	May-02 to April-07	70.4	53.7	-16.7	-24%

Finally, the five-year fixed-price option has provided needed price stability for QFs, many of which are renewable and whose costs are not directly related to gas price fluctuations, and has shielded QFs from regulatory and market uncertainty. Indeed, experts have noted that fixed prices remain essential to fostering a growing domestic renewable energy market. A recent article in an industry journal noted that, "[c]ountries that are currently leading in manufacturing and installation of renewable energy systems have achieved their success by establishing what are known as advanced renewable energy tariffs ("ARTs"). The concept is simple--ARTs help connect renewable systems to the grid and then specify fixed prices to be paid for renewable energy generation. . . ARTs eliminate two of the biggest obstacles inhibiting renewable energy development--the ability to connect to the grid, and market uncertainty (by providing fair prices for an extended period of time to warrant the financial risk of investment). Furthermore, ARTs enable . . . market adoption of a variety of renewable options, both large and small . . . ."[11] In

[11] Jose Etcheverry, *Smart electricity options: the renewable energy market has potential, but only if the right policies are in place*, ALTERNATIVES J., Jan. 1, 2005, at 32.

light of the foregoing, the Commission should adopt a renewed five-year fixed-price option for QFs with existing contracts.

Q: How should the Commission establish the five-year fixed energy price?

A: The five-year fixed energy price should be a five-year forecast of SRAC prices based on the adopted SRAC formula. For example, if the Commission adopts the SRAC formula proposed by CCC witness Beach (i.e. SRAC equals the product of a gas price and an incremental energy rate ("IER") plus an operation and maintenance ("O&M") adder), the fixed price would be the product of the adopted IER and the prevailing five-year forward burnertip-gas price, plus the adopted O&M adder. Because changes to the IER over time cannot be predicted or indexed as easily as changes to O&M costs, and because the IER can increase or decrease on a year-to-year basis, the Renewables Coalition proposes to lock-in the prevailing IER component for five years. Since O&M costs tend to escalate with inflation, the O&M adder in the algorithm should escalate each year based upon changes to the Consumer Price Index.

Q: How would individual QFs elect the fixed price option?

A: The Renewables Coalition proposes that eligible QFs be given a 12-month period in which to elect the fixed price. For those QFs who are currently being paid under the existing five-year amendments, the 12-month period would commence with the expiration of each such QF's amendment. The Renewables Coalition anticipates that these amendments will begin expiring in June 2006 and continue expiring through April 2007 (the "Expiration Period"). At the beginning of each month that falls within the Expiration Period and for 12 months thereafter, the IOUs would calculate the fixed price available for QFs with expiring amendments based upon the prevailing five-year forward burnertip-gas price. At that time, each QF with an expiring amendment would have until the end of its 12-month period to determine whether to elect the new fixed rate or to receive SRAC pricing. QFs that do not currently have a five-year price amendment would be assigned a month falling in the Expiration Period at random by the relevant IOU, to mark the commencement of their 12-month period.

Q: Who would be eligible to receive the five-year fixed rate?

A: All QFs currently under contract with an IOU that receive SRAC prices would be eligible to receive the fixed rate, including QFs that recently executed five-year SO1 contracts with the IOUs. It would be at the QF's discretion to adopt the fixed rate or to remain with SRAC prices. If the QF had five years or more remaining on its current contract, the price would be fixed for five years.[12] If the QF had less than five years remaining on its contract, then the fixed rate would continue until the expiration of the contract.

Q: How would a renewed five-year fixed rate contract option impact ratepayers?

A: In Public Utilities Code section 399.11, the California Legislature acknowledged that "[i]ncreasing California's reliance on renewable energy resources may promote stable electricity prices, protect public health, improve environmental quality, stimulate sustainable economic development, create new employment opportunities, and reduce reliance on imported fuels." Moreover, in Public Utilities Code section 390.1, the California Legislature directed that "[a]ny nonutility power generator using renewable fuels that has entered into a contract with an electrical corporation prior to December 31, 2001, specifying fixed energy prices for five years of output may negotiate a contract for an additional five years of fixed energy payments upon expiration of the initial five-year term, at a price to be determined by the [C]ommission." Implementation of a renewed five-year fixed rate contract option will ensure that ratepayers and the state as a whole continue to realize the acknowledged benefits of renewable energy by using the contract option that already has been endorsed by the California Legislature. Importantly, as long as the Commission sets the fixed rate at a level that reflects the IOUs' avoided costs, as proposed by the Renewables Coalition, ratepayers will realize all of the efficiency, reliability, environmental and other benefits of QF power without incurring additional costs (and potentially save money, as exemplified by the current five-year fixed rate). This will ensure that ratepayers are indifferent to purchases of QF power, as required by PURPA and FERC's avoided cost regulations. Further, renewing the five-year fixed rate contract option will limit ratepayers' exposure to fluctuations in market prices. Because SRAC payments to QFs are currently, and in the future will likely continue to be, based on a formula that includes a gas-price index, if the gas price increases, the SRAC payment increases. The renewed five-year fixed rate contract option

[12] While the Renewables Coalition recommends a five-year fixed rate option, it would support the Commission's adoption of a longer fixed rate term as long as an escalation factor is included.

would act as an insurance policy against such gas-price related fluctuations in SRAC prices. Renewing the five-year fixed rate contract option is also consistent with the Commission's desire to limit the IOUs' exposure to the volatility of spot electricity-market prices to five percent of their resource portfolio.[13]

Q: How would the renewed five-year fixed rate contract option benefit renewable QFs and the IOUs?

A: As the current five-year fixed rate demonstrates, a renewed five-year fixed rate contract option would provide needed price stability for QFs and would shield them from regulatory and market-price uncertainty. In particular, because renewable QFs' costs are not directly related to gas prices, the renewed five-year fixed-price option would give renewable QFs the ability to choose a rate that is not tied to gas-price fluctuations. This highlights the potential benefit to ratepayers of the IOUs locking-in five-year, fixed-price contracts with QFs now. Even if the fixed rate turned out to be lower than the variable SRAC rate over the five-year period, the value of price certainty would, to some degree, offset this difference because such certainty allows renewable QFs to make capital investments with more confidence. These benefits to existing renewable QFs in turn would benefit the IOUs, as the QFs would maximize their generation and thus help the IOUs to meet their RPS program targets.

Another positive impact that would result from the Commission's renewal of the fixed-price option is that renewable QFs would continue to be able to use the accrual method to value revenues under their contracts in their financial statements. In 1998, the Financial Accounting Standards Board ("FASB") issued a new accounting standard, which became effective after June 15, 2000. This new standard requires contracts with price-adjustment provisions based on an indirectly related price index (i.e. derivatives contracts) to be valued on a mark-to-market basis.[14] Under mark-to-market accounting, changes in the fair value of contracts are recorded in earnings currently, rather than as the product is delivered, as under accrual accounting.

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[13] *See, e.g.* D. 04-10-035.

[14] *See* Derivatives Implementation Group, Statement 133 Implementation Issue No. C20, *available at* <http://www.fasb.org/derivatives/issuec20.shtml>.

In the absence of a renewed five-year fixed-price option, upon expiration of their fixed-price contracts, QFs would receive payments for their energy sales equivalent to the IOUs' SRAC. Accordingly, because SRAC payments are based on gas-prices (assuming that changing gas prices still drive SRAC prices), which are not related to renewable QFs' underlying products, such QFs would have to switch from the accrual method of accounting to the mark-to-market method of accounting when valuing revenues under their power purchase agreements. If this were to occur, a discrepancy would emerge between renewable QFs' actual earnings pursuant to their power purchase agreements and the valuation of such power purchase agreements pursuant to mark-to-market accounting. This would introduce a perception of a significant amount of risk for potential investors, thus discouraging investment in both existing and new QFs, and thereby increasing the likelihood that existing renewable facilities would be taken offline. The Commission's adoption of a renewed five-year fixed-price option for QFs with existing contracts would eliminate the potential negative impact of the FASB standard and thus encourage investment in existing and new renewable QFs, thereby increasing the likelihood of the IOUs being able to depend on existing renewable power to help meet their RPS program targets.

Q: What will prevent the renewed five-year fixed rate contract option from being substantially above-market?

A: The Renewables Coalition recognizes that requiring the IOUs to offer a renewed fixed rate option for QFs may provoke negative associations with the forecasted energy prices that the Commission adopted during the 1980s. These ten-year fixed energy prices were based upon the assumption of continued oil-price increases and proved to be substantially above-market (in part, because QFs helped to reduce our dependence on foreign oil). Many QFs subscribed to these attractive prices. This problem, however, is unlikely to repeat itself.

First, the proposed five-year fixed rate contract option would only be offered to QFs that are already built and have operated reliably for many years under existing contracts. There will be no gold rush of new QFs that subscribe to this option. Second, the proposed five-year fixed rate contract option is for a much shorter term than the contracts implemented in the 1980s, so any resulting price inaccuracies, whether upward or downward, are less likely and would have a much smaller impact if they occurred. Finally, there is no reason to think that the new gas prices

that will be used to calculate the renewed fixed-rate will be as inaccurate as past forecasts. Past fixed prices were based upon oil-price forecasts for which there was no forward market and that were subject to extreme geopolitical influences (i.e. price-setting by the Organization of the Petroleum Exporting Countries). Today, there are forward markets for natural gas that provide more accurate, detailed information for market participants to use in setting five-year gas prices. Accordingly, any discrepancies between current gas-price forecasts and actual prices should not be as severe as before.

Q: What is the Renewables Coalition's response to the argument recently raised by Edison, PG&E and SDG&E that the Commission is not authorized to establish a five-year fixed-price contract option?

A: In an e-mail sent to ALJ Halligan and ALJ Brown on August 16, 2005, Edison, PG&E and SDG&E assert that it is inappropriate to consider whether to renew the five-year fixed-price contract option because "[n]o provision of the standard offer agreements or of PURPA authorizes the Commission to establish a fixed, five year price of energy in lieu of the price of energy at the time of delivery in existing contracts."[15] Specifically, the IOUs argue that standard offer agreements require the Commission to establish a short-run avoided cost calculated at the time of delivery and that "[a] five-year fixed price, by definition, does not represent the IOUs' cost at the time of delivery, but rather, necessarily entails a forecast of future utility costs."[16] The IOUs also argue that the Commission does not have jurisdiction to modify the terms of existing standard offer contracts.

I will leave it to the lawyers to argue about whether the Commission can legally require the IOUs to offer a fixed-price option for QFs. I will note, however, that contrary to the assertion of the IOUs, FERC has explained that PURPA clearly permits the use of forecasting in setting SRAC prices. FERC explained the meaning of the phrase "avoided costs calculated at the time of delivery" in its Order No. 69 adopting its avoided cost regulations. FERC explained that it had revised Section 292.304(d)(1) "to provide that the rates for purchase are to be based on the

[15] E-mail from Mary Gandesbery to ALJ Halligan, ALJ Brown and Service List in R. 04-04-003, "Re: CAC/EPUC, IEP and CCC Comments on Joint Outline" (August 16, 2005).
[16] *Id.*

purchasing utility's avoided costs *estimated* at the time of delivery."[17] The version of Section 292.304(d)(1) that was adopted by FERC in Order No. 69 is the same version that appears in FERC's regulations today.

Section 292.304(d)(1) specifies that rates applicable to as-available purchases shall be based on the purchasing utility's "avoided costs calculated at the time of delivery."[18] FERC's discussion in Order No. 69 demonstrates that a utility's "avoided costs *calculated* at the time of delivery" are intended to reflect a utility's avoided costs *estimated* at the time of delivery.

In addition, I am aware of nothing in the standard offer contracts, PURPA or FERC's regulations pursuant to PURPA that dictates how often forecasts of SRAC must be made or revised. Indeed, FERC has explained that the reference in PURPA to the "incremental cost of alternative energy" was never "intended to require a minute-by-minute evaluation of costs which would be checked against" forecast rates.[19] FERC instead agreed with parties who "stressed the need for certainty with regard to return on investment in new technologies."[20] Indeed, the Commission itself has acknowledged that, "PURPA requires a reasonable approximation of avoided costs over time."[21] The Commission has employed SRAC parameters over various time periods ranging from monthly adjustments of gas prices to one-year and two-year forecasted IERs to the current SRAC formula for PG&E and SDG&E, much of which has not changed in almost a decade.

Finally, if the Commission desires to avoid a legal battle regarding whether it can require the IOUs to offer the fixed price amendments, the Commission can always (i) require the IOUs to determine a five-year price in the manner set forth above; (ii) rule that such a price will be considered *per-se* reasonable; and (iii) hold the IOUs financially responsible if they fail, in their administration of the QF contracts, to offer to amend QF contracts to lock-in the price and SRAC prices turn out to be higher than the five-year fixed price. There is no question that the

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[17] *Id.* (emphasis added).
[18] 18 C.F.R. § 292.304(d) (2003).
[19] FERC Stats. & Regs., Regs. Preambles 1977-1981 ¶ 30,128 at 30,870, 45 Fed. Reg. 12,214, at 12,224 (1980).
[20] *Id.*
[21] *Order Modifying Decision (D.) 03-12-062 and D.04-01-050, and Denying Rehearing of D.03-12-062 and D.04-01-050 as Modified,* D.04-07-037 at 6 (C.P.U.C. 2004) (citing 18 C.F.R. § 292.304(b)(5)).

Commission retains jurisdiction over the IOUs' administration of QF contracts. This idea is similar to what the Commission already did in adopting the existing five-year amendments.

V.E A LONG-TERM QF POLICY

Q: What is the Renewables Coalition's proposal for a long-term QF policy?

A: The Renewables Coalition supports the long-term QF policy proposed by the CCC in its proposal for a long-term QF policy filed in Rulemaking 04-04-003 on November 10, 2004. In particular, the Renewables Coalition agrees that:

1. The Commission should adopt a long-term firm capacity contract for QFs whose contracts expire and for new QFs. The new contract should have a 15-year term and be priced using the long-run avoided cost ("LRAC") methodology being developed in this proceeding and should contain the terms outlined by the CCC in its filing (which are based largely on the Commission's existing standard offer contracts).

2. The Commission should adopt an as-available capacity contract based upon the current SO1 contract for renewable QFs. The contract should contain as-available capacity and SRAC energy pricing. The as-available capacity contract should extend for a term of up to at least 15 years, and should be terminable by the QF upon 30 days prior notice by the QF, as was the QF's option in the original SO1. As explained earlier, the as-available capacity price should be updated as required by PURPA to reflect the IOUs' current avoided costs.

3. The firm capacity contract should be available (i) to existing QFs upon expiration of their current contracts and (ii) to new renewable QFs in each IOU's service territory at least until the IOU has met its RPS target.

The Renewables Coalition agrees with the explanations offered by the CCC in support of these proposals and will not repeat them here. Rather, the Renewables Coalition expands below upon four issues raised by the CCC's proposal (as supported by the Renewables Coalition): (1) how long-term contracts will effectuate the Commission's goals, as stated in Decision 04-01-050, of encouraging upgrades to existing QF facilities and fostering investment in new QFs; (2) why a long-term QF policy is needed to complement the RPS program; (3) why a long-term policy is needed to ensure that PURPA's must-purchase obligation is fulfilled; and (4) why existing QFs should not be required to negotiate new interconnection agreements or to conduct new interconnection studies upon executing a long-term contract.

Q: How will the proposed long-term QF procurement policy promote renewable generation in California, as directed by the Commission in Decision 04-01-050?

A: In Decision 04-01-050, the Commission agreed with the CCC that "QFs provide numerous benefits to California, including environmental characteristics, efficiency, contributions to the local economy, as well as power resources"[22] and concluded that, "[i]t is in the State's interest for QFs to continue to provide those benefits over the long term, especially where they are already in existence."[23] The Commission also found that the IOUs will need QF power in order to meet their baseload-power needs as existing QF contracts expire.[24] Further, in Decision 04-01-050, the Commission stated its desire "to encourage existing QFs to continue providing power over the longer term to the utilities" and to "encourage efficiency upgrades to existing [QF] facilities."[25] A policy establishing long-term contracts at LRAC prices will address the findings and concerns of the Commission made in Decision 04-01-050 by encouraging existing QFs to upgrade their facilities and supporting investment in new QFs. Like all businesses, renewable QFs (and lenders thereto) will not invest significant capital, either in the form of upgrades to existing facilities or in the form of new facilities, without assurance of a market for their product. Long-term contracts with the IOUs at LRAC prices provide such a market.

Q: Why is the proposed long-term QF procurement policy needed as a complement to the RPS program solicitations?

A: The Renewables Coalition urges the Commission to view the long-term QF contract options as a backstop mechanism to the RPS program that is designed to ensure that the many benefits of existing renewables are not lost. This backstop is needed because the RPS program solicitations do not ensure that existing renewable QFs will have purchasers for their power upon the expiration of their existing contracts. First, if the IOU is not conducting a solicitation at or near the time of a renewable QF's contract expiration, the QF may have no purchaser for its power. There are several reasons why an IOU may not be conducting a solicitation at any given time. For example, IOUs are only required to meet their annual procurement targets through

[22] D.04-01-050 at 151, *see also* Finding of Fact 71.
[23] *Id.* at 151.
[24] *Id.* at 155.
[25] *Id.* at 157.

solicitations if there are adequate Public Goods Charge ("PGC") funds available to support payments in excess of the RPS market price referent ("MPR"). The IOUs are also given unlimited flexibility to bank excess renewable procurement from one year and apply the banked amounts to future years. The IOUs are also under no obligation to procure from renewables in excess of the 20 percent limit established by the RPS program. With conditions such as these, the fate of existing renewable QFs whose contracts are expiring is uncertain in the absence of a long-term contract option to complement the RPS program.

Second, the structure of the RPS program solicitations risks excluding existing renewables from the IOUs' portfolios. The RPS program requires the IOUs to solicit competing bids and to select the lowest-cost supplier that best fits the IOUs' resource needs. Further, the IOUs are required to pay for power only up to the MPR. Existing renewables are significantly disadvantaged by the fact that they, unlike new renewables, are not eligible to obtain Supplemental Energy Payments ("SEPs") from the PGC fund to the extent that their bid prices are higher than the MPR. Consequently, an existing project has virtually no hope of obtaining a contract in an RPS solicitation if its bid price is in excess of the MPR while a new renewable project may be successful if it bids in excess of the MPR (as any overage is covered by SEPs). Indeed, an RPS program solicitation could lead to the counter-intuitive result of a new renewable that is significantly more expensive than an existing renewable prevailing if both resources exceed the MPR. For example, assume that an existing renewable QF places a bid of $65/MWh while a new renewable QF places a bid in the same solicitation of $70/MWh. Assume further that both of these QFs are then short listed by the IOU. The IOU then calculates the baseload MPR to be, for my example, $57/MWh. The result would be that the more costly new QF would obtain a contract and receive SEPs to cover the $13/MWh difference between its bid and the MPR, while the less expensive existing QF would not obtain a contract. And, limited SEP funds will be expended on subsidizing the new QF's bid so that it equals the MPR, even though the existing QF could have provided the power at a more reasonable price with less drain on the limited state funds.

Third, both new and existing QFs of small size (under 50 MW) are far less able to compete in RPS solicitations than are large projects. Many small QFs simply cannot comply with some of the terms and conditions in the utility solicitations. For example, the IOUs are

seeking substantial credit guarantees and stringent performance requirements. In addition, the transaction costs of participating in an RPS solicitation, including months of negotiation, are too high for many small companies to bear.

Fourth, it is widely recognized that certain renewable technologies are not currently as cost-effective as other renewable technologies. For example, existing biomass facilities will be unable to compete with state-of-the-art wind or geothermal resources. This is true, in part, because federal tax incentives favor new wind and geothermal technologies over existing biomass facilities.[26] The RPS program is simply not likely to be a viable option for the more costly resources. Yet, with long-term LRAC contracts complementing the California Energy Commission's Existing Renewables Program Tier I PGC payments (for which existing biomass and solar-thermal projects are eligible), renewable resources can continue to provide needed renewable energy supplies to California, support the local tax base, employ hundreds of workers throughout the state, and improve air quality by reducing the open-air burning and decomposition of biomass wastes.

Q: Will offering renewable QFs standard long-term contracts undermine the RPS program?

A: No. The RPS program offers bidders a chance for a long-term contract, with SEPs for new projects to supplement IOU payments capped at the MPR. A firm contract option is likely to be unattractive to certain renewable technologies (e.g., intermittent technologies) as it involves firm capacity obligations. Further, the as-available option bases prices upon SRAC, which is significantly more volatile than the fixed price that can be expected in contracts from the RPS program. Thus many renewables will continue to prefer to participate in RPS program solicitations. Meanwhile, if LRAC prices are set correctly by the Commission, ratepayers should be indifferent to the method of procurement of the renewable power, whether it is RPS derived

[26] Existing biomass facilities recently received a federal production tax credit ("PTC") through the end of 2009, at half the amount available to new wind and geothermal generators, although effectively at only a quarter of the amount available to new wind and geothermal resources. This is because most existing biomass plants in California used tax-exempt bonds to finance much of the capital cost of the plants during the 1980s. This use was authorized by the by the California Pollution Control Finance Authority, which considered the waste consumption of the biomass plants to be a form of pollution control. Under federal law, the PTC eligibility of biomass plants that used tax-exempt bonds is reduced by a further 50 percent, rendering them eligible for only 25 percent of the PTCs for which new wind and geothermal resources are eligible.

or pursuant to a QF contract. Finally, as explained above, the Commission has already found in Decision 04-01-050 that participation in a competitive solicitation such as the RPS program should not be mandatory for QFs who wish to extend their existing contracts.

Q: Why is the long-term QF procurement policy needed to satisfy PURPA?

A: By express provision of California law, the Commission's implementation of the RPS program does not constitute implementation of PURPA.[27] Further, FERC has found that the opportunity for QFs to participate in utilities' competitive solicitations does not satisfy PURPA's must-purchase obligation.[28] As such, mere reliance on the RPS program for renewable QF procurement is not sufficient to meet the requirements of PURPA. Meanwhile, by adopting the long-term policy proposed by the CCC and supported by the Renewables Coalition, the Commission would ensure that utilities, to some degree, are still required to take power and capacity from QFs at full avoided cost prices, as required by PURPA.

Q: Does Congress' recent amendment of PURPA's must-purchase obligation impact the above analysis?

A: No. Section 1253 of the Energy Policy Act of 2005 modifies section 210 of PURPA to repeal prospectively the must-purchase obligation in certain competitive situations. Specifically, Section 1253 establishes that the obligation of an IOU to enter into a new contract or obligation to purchase energy from an individual QF shall remain in place until FERC determines that the QF has non-discriminatory access to:

(a) "independently administered, auction-based day ahead and real time wholesale markets for the sale of electric energy" and "wholesale markets for long-term sales of capacity and electric energy;" or

(b) "transmission and interconnection services that are provided by a FERC-approved regional transmission entity and administered pursuant to an open access transmission tariff that affords nondiscriminatory treatment to all customers" and "competitive wholesale markets that provide a meaningful opportunity to sell

[27] Public Utilities Code § 399.15(d).
[28] *See Cogen Lyondell, Inc. et al.*, 95 F.E.R.C. ¶ 61,243 (2001).

capacity, including long-term and short-term sales, and electric energy, including long-term, short-term and real-time sales, to buyers other than the utility to which the QF is interconnected. In determining whether a meaningful opportunity to sell exists, FERC shall consider, among other factors, evidence of transactions within the relevant market;" or

(c) "wholesale markets for the sale of capacity and electric energy that are, at a minimum of comparable competitive quality as markets described in paragraphs (a) and (b) above."

Section 1253 clearly envisions that the must-purchase obligation will remain until these conditions are met, which may be quite a long time from now. FERC has not yet issued orders responding to applications from any of the IOUs seeking relief from PURPA's must- purchase obligation on a service territory-wide basis, as required by Section 1253. Moreover, as a substantive matter, it is unlikely at this time that FERC would find that a regional transmission entity provides California QFs a meaningful opportunity to sell energy to entities other than the IOUs to which they are interconnected. Similarly, the California Independent System Operator would likely have to significantly overhaul its structure, protocols and transmission tariff before FERC would find that the requirements of Section 1253 have been met for California's IOUs. Finally, Section 1253 allows QFs to apply to reinstate an IOU's must-purchase obligation upon showing that the requirements described above are no longer being met. In light of the foregoing, PURPA's must-purchase obligation remains a requirement for the foreseeable future and, even after repeal, can be reinstated.

Q: Should existing QFs that sign new long-term contracts be required to conduct new interconnection studies or to sign new interconnection agreements that contain different terms and conditions than their prior agreements?

A: No. For a QF with a contract that has expired, or is set to expire, the new long-term contract should provide for the extension of existing interconnection arrangements, assuming the QF does not significantly increase its current output.

First, if a QF is already interconnected and supplying power to an IOU, there is no practical reason to require that QF to perform new interconnection studies or to comply with other interconnection requirements that are applicable to newly constructed facilities. Such existing QFs have been safely transmitting their power over existing interconnection facilities, and their new contracts simply seek to continue to transmit the same power over the same lines. So long as a QF does not materially increase its output, there is no reason to require it to conduct a new interconnection study as part of its execution of a new contract.

Second, in Order No. 2006, which establishes standardized interconnection agreements and procedures for generators that are less than or equal to 20 megawatts in size, FERC found that "Transmission Providers should, of course, use existing studies instead of performing additional analyses to reduce costs for the Interconnection Customer, whenever possible. The Interconnection Customer is not to be charged for such existing studies; however, it is responsible for costs associated with any new study and any modification to an existing study that is *reasonably necessary* to evaluate the proposed interconnection."[29] Similarly, in Order No. 2003, which established standardized interconnection agreements and procedures for large generators, FERC concluded that the owner of a QF currently interconnected to a transmission system that becomes FERC-jurisdictional by either terminating their QF status or deciding to sell power in the wholesale market need not submit an interconnection request (eliminating the requirement for a new interconnection study) if the output of the generating facility will be substantially the same as before.[30] Further, in Order No. 2006, FERC rejected a request by Pacificorp to be allowed to perform additional studies after an interconnection is operating. FERC explained that, "[t]he purpose of the evaluation processes is to determine the effect the interconnection will have on the Transmission Provider's electric system. Such evaluations are also performed to ascertain the Interconnection Customer's cost responsibility for Interconnection Facilities and Upgrades. We reject PacifiCorp's proposal because accepting it

[29] Standardization of Small Generator Interconnection Agreements and Procedures, Order No. 2006, 70 Fed. Reg. 34190-01, 34208 (June 13, 2005); 111 F.E.R.C. 61,220 at ¶ 187 (2005) (Order No. 2006).
[30] Standardization of Generator Interconnection Agreements and Procedures, Order No. 2003, 68 Fed. Reg. 49846-01, 49918 (Aug. 19, 2003); 104 F.E.R.C. at ¶ 812, 815 (2003) (Order No. 2003).

would make determination of cost responsibility open-ended and create uncertainty for the Interconnection Customer."[31]

While Order No. 2006 may not be directly applicable to many renewable QFs' interconnections, since they do not involve FERC-jurisdictional facilities, the logic of Order No. 2006 still holds. Indeed, FERC stated in Order No. 2006 that "our hope is that states may find this rule helpful in formulating their own interconnection rules."[32] In the case of renewables with existing interconnection arrangements, they should not have to bear the cost and delay precipitated by a new interconnection study when the existing interconnection study sufficiently addresses the utilities' concerns about reliability and safety. Further, exposing renewables with existing interconnection agreements to the possibility of restudy would introduce an unacceptable amount of uncertainty regarding interconnection costs. For these reasons, the Commission should require the IOUs to provide renewables with existing interconnection arrangements to apply the terms of such arrangements to their new long-term QF contracts.

Q: To what extent should the capital-recovery charges paid by a QF with existing interconnection arrangements change upon that QF's execution of a new long-term QF contract?

A: Upon the expiration of an existing QF's contract, the capital expenditures by the IOU to build the interconnection facility to transmit power pursuant to that contract should have been fully amortized, according to the terms of that QF's interconnection agreement. Assuming that the QF does not require the construction of additional facilities to transmit power pursuant to its new long-term QF contract, the QF should no longer have to pay any capital-expenditure charge because the cost of constructing the interconnection facilities at issue have already been paid.

Q: Does this complete your testimony?

A: Yes.

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[31] 111 F.E.R.C. at ¶ 195.
[32] *Id.* at ¶ 8.