

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

Order Instituting Rulemaking to Promote)	
Consistency in Methodology and Input)	
Assumptions in Commission Applications of)	R. 04-04-025
Short-run and Long-run Avoided Costs,)	(Issued April 22, 2004)
Including Pricing for Qualifying Facilities)	
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**Pre-Workshop Reply Comments
of the California Cogeneration Council**

Jerry R. Bloom, Esq.
Joseph M. Karp, Esq.
White & Case, LLP
Three Embarcadero Center, Suite 2210
San Francisco, CA 94111
Telephone: (415) 544-1100
Facsimile: (415) 544-0202
E-mail: jbloom@whitecase.com
jkarp@whitecase.com

R. Thomas Beach
Patrick G. McGuire
Crossborder Energy
2560 Ninth Street, Suite 316
Berkeley, California 94710
Telephone: 510-649-9790
Facsimile: 510-649-9793
E-mail: tomb@crossborderenergy.com
patrickm@crossborderenergy.com

On behalf of
CALIFORNIA COGENERATION COUNCIL

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Table of Contents

There Is No Need to Resolve “Threshold” Legal Issues, as Edison Alleges	2
The Commission Has Not Found That Current SRAC Values Violate PURPA	4
Both LRAC and SRAC Pricing Are Applicable to QFs	5
The E3 Report Provides a Good Framework for LRAC Pricing	7
Current Electric Market Prices Are Not Suitable for Avoided Costs	9
The Commission Must Continue to Recognize the Value of As-Delivered Capacity	10
Conclusion	12

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The California Cogeneration Council (CCC) respectfully presents these pre-workshop reply comments in Order Instituting Rulemaking No. 04-04-025 (the OIR). This OIR focuses on issues concerning the Commission’s methodology for calculating “avoided costs” — the costs that the regulated California electric utilities (IOUs)¹ avoid as a result of energy conservation programs, distributed generation (DG) resources, new renewable generation, and purchases from qualifying facilities (QFs).

As directed in the OIR, the CCC’s opening comments focused on a Commission-sponsored study prepared by Energy and Environmental Economics (the “E3 Report”)² that proposes a comprehensive avoided cost methodology. Although it is not perfect, the E3 Report provides an excellent starting point, in the CCC’s view, for the development of a long-run avoided cost (LRAC) methodology that is broadly applicable to a variety of resource options. Many of the elements of the E3 Report also can be used in short-run avoided cost (SRAC)

¹ Pacific Gas & Electric Company (PG&E), Southern California Edison Company (Edison), and San Diego Gas & Electric Company (SDG&E). Southern California Gas Company, SDG&E’s affiliated gas distribution company, joined SDG&E’s comments. These comments refer to SoCalGas and SDG&E jointly as “Sempra.”

² “A Forecast of Cost Effectiveness of Avoided Costs and Externality Adders,” released January 8, 2004 to parties in R. 01-08-028

pricing for existing QF contracts. In contrast, the opening comments of the IOUs generally express greater skepticism that the Commission can make progress toward the goal of the OIR — a consistent and comprehensive avoided cost methodology. In these reply comments, the CCC replies briefly to the IOUs’ opening comments in a number of areas.

I. There Is No Need to Resolve “Threshold” Legal Issues, as Edison Alleges.

The CCC agrees with the Commission’s conclusion in the OIR that the current SRAC pricing methodology needs to be reviewed and updated to reflect today’s circumstances. However, the CCC does not agree with Edison’s assertion that the Commission first needs to resolve certain “threshold” legal issues concerning the Commission’s ability to update its short-run avoided cost pricing formula.³ Edison’s first issue is whether the state’s statutory framework for avoided cost pricing, Public Utilities Code Section 390, is consistent with federal law. If Section 390 is not consistent with federal law, then Edison raises the problem that, under the California Constitution, a state agency such as the Commission cannot declare a state law invalid due to federal pre-emption.

As the CCC explained in its opening comments, the Commission has the ability to modify essential parameters of the current SRAC formulas, while remaining within the ambit of Section 390.⁴ Indeed, that is precisely what the Commission did to Edison’s SRAC formula in D. 01-03-067 — the Commission updated the intrastate transportation rate that was a key input variable to the natural gas price used in the Edison SRAC formula.⁵ Although the CCC argued at

³ Edison Pre-workshop Comments, at 13-15. In addition to these legal issues related to SRAC, on page 12 of its comments Edison argues that the market price referents used in the Renewables Portfolio Standard (RPS) program cannot lawfully exceed avoided cost under PURPA. Edison made the same legal argument in the RPS proceeding (R. 01-10-024), and the Commission decisively rejected it in D. 03-06-071, at 24-27.

⁴ CCC Pre-workshop Comments, at 18.

⁵ The Commission also indicated in D. 01-03-067 that, if one element of the Edison SRAC formula was updated, all of the elements of the formula should be updated, in order to

that time that this action violated Section 390(b), the Commission's decision was upheld through the appellate process. Given this history, the CCC does not believe that there are legal issues that must be resolved before SRAC parameters are reviewed. In this respect, the CCC agrees with PG&E that SRAC prices can be reformed in a manner that is consistent with Section 390.⁶

The CCC does agree with Edison, however, that Code Section 390 places important constraints on the methodology that the Commission must use to set SRAC. Most important, Section 390(b) requires that the SRAC formula must be indexed to natural gas prices at the California border. Thus, Section 390(b) precludes the use to set SRAC prices of measures such as published electric market prices, or of natural gas prices in the producing basins. However, as the CCC explained in its opening comments, the Commission can and should use the basic formula for SRAC prices on which the Commission has relied for the past two decades:

$$\text{SRAC Energy} = \text{Gas Price} \times \text{IER} + \text{Variable O\&M} + \text{Other Adders}$$

This approach to SRAC is well-understood by all of the involved parties and by the Commission. Linking SRAC to natural gas prices continues to make sense given the state's increasing dependence on that fuel for electric generation. Gas-fired QFs benefit from this linkage because their input and output prices move in tandem, reducing the risk that volatility in either the gas or electric markets will make their generation uneconomic. The CCC recommends that the Commission should return to the use of this formula to set SRAC prices going forward.

ensure an internally consistent SRAC calculation. Although the Commission held hearings in 2001 on updating the other elements of the Edison SRAC formula, a decision on those updates has never been issued. Thus, in 2001 the Commission found no legal impediment to updating all of the key components of Edison's SRAC formula.

⁶ PG&E Pre-Workshop Comments, at 11.

II. The Commission Has Not Found That Current SRAC Values Violate PURPA.

Edison asserts that “the Commission has effectively acknowledged that the current SRAC methodology yields prices exceeding avoided cost.”⁷ This is not true — the Commission has simply found that SRAC prices have exceeded market prices “in certain time periods” and that the utilities have paid too much for QF power “at certain times of day.”⁸ The fact that SRAC prices may exceed market prices “in certain time periods” in no way means that SRAC prices violate PURPA.

The concerns that the Commission expressed in D. 03-12-062 were based on comparisons in PG&E’s testimony in R. 01-10-024 between SRAC prices and bilateral wholesale electric prices published by Dow Jones.⁹ It is highly questionable whether the Dow Jones prices accurately represent the IOUs’ short-run avoided costs for the large block of existing QF generation in California, given that the amount of QF generation now paid SRAC prices (virtually all of the 10,000 MW of QFs now under contract to the three IOUs) dwarfs the relatively thin bilateral electric market in California (Dow Jones reports about 2,500 MW of daily bilateral transactions in NP-15 and SP-15¹⁰). If the IOUs actually had to turn to the wholesale market to replace their QF purchases, the market price for that power would be substantially higher than today’s published market prices for the small amount of power now traded “around the edges” of the long-term contracts that supply most of the IOUs’ resources. In fact, without

⁷ Edison, at 5.

⁸ D. 03-12-062, at 57-58 .

⁹ PG&E testimony in R. 01-10-024, filed July 14, 2003, Chapter 6, at 6-5 to 6-7.

¹⁰ Based on the most recent twelve months (June 2003 – May 2004) of daily market volumes reported by Dow Jones.

QFs, the IOUs undoubtedly would not be able to serve their loads without building additional short-term generation, presumably combustion turbines.¹¹

Furthermore, as the CCC discussed in its opening comments, the Commission has never expected SRAC prices to track the IOU's actual avoided costs on an hour-to-hour, day-to-day, or even week-to-week basis. In fact, SRAC prices have never been revised more often than monthly, and only one SRAC parameter — the natural gas price — is updated on a monthly basis. Before the current SRAC formulas were adopted, IER and variable O&M values were updated at most every year, and often every two or three years. The time-of-use factors used to time-differentiate QF prices have not been revised for many years. As a result, it is to be expected that at times SRAC prices will exceed the IOUs' actual avoided costs, and at other times SRAC will fall below the IOUs' avoided costs. Moreover, if the Commission believes that SRAC prices are too high “in certain hours,” and that this discrepancy results in the utilities paying too much for QF power, then the obvious remedy is for the Commission to revise those prices to more closely align them with the IOUs' avoided costs. This is precisely the task that the Commission has set for this OIR. Until that update is accomplished, the CCC agrees with Sempra that “the current SRAC methodology yields appropriate results and should be maintained.”¹²

III. Both LRAC and SRAC Pricing Are Applicable to QFs.

Edison suggests that this case should focus only on QF avoided cost issues; in a similar vein, PG&E recommends that the Commission move all QF pricing issues to a separate track in this proceeding.¹³ The CCC acknowledges that short-run avoided cost pricing involves special

¹¹ QFs provide about 20% of the generation on the California ISO's system, a share that substantially exceeds reserve margins on the ISO-operated grid. See Figure 1 of the CCC's pre-workshop opening comments.

¹² Sempra Pre-workshop Comments, at 10.

¹³ Edison, at 16; PG&E, at 11.

constraints (e.g. P.U. Code Section 390) and that these constraints may merit a separate procedural track to focus on SRAC issues. However, the CCC strongly disagrees with the IOUs that the E3 Report's LRAC methodology has no application to QF pricing. Certain elements of avoided costs – in particular avoided generation costs – are the same across a wide range of applications of avoided cost.

Moreover, QFs whose power is priced at LRAC appear likely to play an important role as one of the IOUs' future resource options. In R. 04-04-003, the Commission has committed to developing a policy for long-term extensions or renewals of QF contracts. QFs that extend, renew, or obtain new long-term contracts should be paid LRAC prices based on a methodology that is reasonably consistent with other LRAC applications. There are significant benefits to the state from offering an LRMC price to new, renewed, or extended long-term QF contracts.¹⁴ First, LRMC prices will not fluctuate with volatile, short-term natural gas prices, and thus will moderate the potential electric rate impacts of the state's growing dependence on natural gas for electric generation. Second, the certainty of a fixed stream of LRAC prices will encourage existing QFs to make the investments needed to keep their projects operational and in compliance with stricter environmental standards. Third, notwithstanding California's experience with the ten years of fixed prices in Interim Standard Offer No. 4 contracts, fixed price contracts do not always disadvantage ratepayers. Indeed, as CalWEA noted in its pre-workshop comments, the 5-year \$53.70 per MWh fixed energy price provided to QFs in the summer of 2001 appears likely to be a reasonable deal for ratepayers, given natural gas price projections for the next two years.¹⁵ That fixed-price contract amendment also ensured that California would be able to rely on production from its full complement of QFs during the critical summer of 2001. When the Commission approved these amendments in June 2001, it

¹⁴ The Commission again should reject Edison's renewed suggestion that QFs seeking a new contract simply should be offered the opportunity to bid for such a contract in an IOU solicitation. Edison, at 11. In D. 03-12-062, at 55-56, the Commission found that such an opportunity does not satisfy the PURPA requirement that utilities must purchase QF power.

¹⁵ CalWEA Pre-workshop Comments, at 2-3.

expressed the view that this fixed price “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.”¹⁶ These benefits have been realized since the summer of 2001. To ensure that the state has the chance to obtain similar benefits in the future, the Commission should develop an LRAC option for new, renewed, or extended QF contracts.

The CCC also supports CalWEA’s recommendation that Commission should direct the utilities to offer to all existing QFs another 5-year fixed-price contract when the 2001 - 2002 contract amendments expire in 2006 or 2007. The new fixed price should be based on a five-year forecast of SRAC prices using the Commission’s then-current SRAC methodology. Such an option will help to reduce the portion of California’s generation portfolio whose costs are exposed to volatile natural gas prices.

IV. The E3 Report Provides a Good Framework for LRAC Pricing.

Several of the IOUs do not believe that the E3 Report’s LRMC methodology is adequate for use in QF pricing. For example, Sempra suggests that the E3 should be limited to serving as “a planning type analysis” to assess the cost-effectiveness of conservation programs.¹⁷ However, the problems with the E3 Report that the utilities cite do not hold up to scrutiny.

The IOUs appear quite confused over how E3’s use of a combined-cycle gas turbine (CCGT) as the basis for avoided generation costs will impact the split between energy and capacity in QF pricing. Edison appears troubled that the use of the full capital cost of a CCGT will overstate the avoided cost of capacity. Sempra worries that the use of the all-in costs of a CCGT for QF pricing may double-count capacity, if such pricing is extended to existing QFs that already receive separate capacity payments. Neither of these concerns poses a problem. In the

¹⁶ D. 01-06-015, at 3.

¹⁷ Sempra, at 9.

E3 LRAC methodology, the “all-in” costs of a CCGT are used as the measure of both energy and capacity costs. For the purpose of LRAC pricing for new long-term QF contracts, there is no real need to separate the LRAC price into energy and capacity components. A single price that combines avoided energy and capacity costs is perfectly appropriate for new contracts. For example, the market-price referents (MPRs) used in the RPS program generally are “all-in” costs that include both energy and capacity costs,¹⁸ and the Commission has seen no need to break them into energy and capacity components. Bid evaluation in the RPS program is expected to be conducted on a total cost basis, without separate energy and capacity components.¹⁹ With respect to Sempra’s concern that capacity may be paid twice to existing QFs, the CCC notes that existing QFs receive energy payments based on SRAC. The SRAC pricing methodology has always been an energy-only price that is used in contracts with separately-stated capacity payments. So long as the LRAC methodology is only used for new, renewed, or extended QF contracts, LRAC prices will not double-count capacity.

Sempra worries that the E3 report may double-count externality costs or line losses.²⁰ The CCC agrees that such costs should not be double-counted, and believes that a reasonable amount of care will ensure that this does not happen. For example, if the capital costs for a CCGT include the costs of all needed NOx and PM10 offsets, then it is not necessary to calculate a separate adder for these emissions. Line losses will not be double-counted so long as losses are calculated under the assumption that the QF and the avoided resource deliver power to the same point.

Sempra suggests that the price elasticity of demand should not be considered in QF pricing because it is a “pecuniary externality” that does not affect the allocation of resources.

¹⁸ See D. 03-06-071, at 24. The only exception is the Commission’s adoption of an optional capacity value for as-available bidders.

¹⁹ See PG&E Opening Brief on Least-Cost, Best-Fit Issues in R. 04-04-026 (June 4, 2004), at 9.

²⁰ Sempra, at 5-6.

This ignores the FERC rules implementing PURPA, which specifically require the calculation of avoided costs to consider “the aggregate value” of QF generation.²¹ Furthermore, the Commission has long recognized that QF SRAC prices should be based on a comparison of total system costs both with and without QFs – this is the essence of the QF_{In}/QF_{Out} methodology that the Commission has used to determine the SRAC heat rate (the “IER”). Thus, avoided costs have included the impact of QF production on the costs of all of the utility’s other resources, even those whose output does not change as a result of QF generation. For example, PG&E’s past SRAC prices included an adder to reflect the impact of QFs in reducing PG&E’s contractual cost of geothermal steam. PG&E’s costs for geothermal steam were indexed to the utility’s costs for thermal generation, which in turn was lower due to the presence of QFs on the system.

V. Current Electric Market Prices Are Not Suitable for Avoided Costs.

PG&E and Edison continue to suggest that avoided costs should be based on electric market prices.²² The CCC addressed this issue at length in its opening comments.²³ Fundamentally, reported market prices from the small, residual wholesale electric market in California are not a sound basis for avoided costs. This is particularly true of the very thin market for forward power, on which the E3 Report mistakenly relies. The energy crisis showed the need to ensure that energy prices derived from reports in trade publications or from anecdotal sources are reliable and robust. One important safeguard is to require the use of multiple publications that are generally accepted to be reliable and robust.²⁴ The Commission should not

²¹ 18 CFR § 292.304(e)(2)(vi).

²² PG&E, at 3-4; Edison, at 11.

²³ CCC Pre-workshop Comments, at 7 - 9.

²⁴ For example, the Commission has long used gas price indices for both SRAC pricing and in its gas cost incentive mechanisms. In those applications, the Commission has taken care to use the average of multiple indices at each pricing point and to use indices that have a substantial track record, reflect market dynamics, track each other, and are generally accepted as robust and reflective of market prices. *See* D. 96-12-028, at 13; D. 96-07-023, at Attachment A.

rely on reported forward electric prices from a single publication, as the E3 Report does, or on “market quotes,” as PG&E suggests. The CCC again notes that, in the June 2003 RPS decision, the Commission declined to use executed contracts, broker quotes, or bids to set the long-term (10 to 20 year) RPS MPRs.²⁵ Finally, P.U. Code Section 390(b) does not allow the use of electric market prices to set SRAC prices. For these reasons, the Commission should not use electric market prices to calculate either LRAC prices or SRAC energy prices.

VI. The Commission Must Continue to Recognize the Value of As-Delivered Capacity.

The Commission has long held that the aggregate deliveries of QFs using intermittent technologies allow the utilities to avoid capacity costs.²⁶ The Commission has allocated avoided capacity costs to time-of-use periods using capacity allocation factors that reflect the relative value of generation in each time-of-use period. Most of the capacity value is allocated to the summer on-peak period. These TOU-specific capacity values are converted to \$ per kWh as-delivered capacity prices, and are paid to as-available QFs based on their energy deliveries in each TOU period. Such time-differentiated capacity prices ensure that as-available QFs only receive significant capacity payments to the extent that they deliver power during the peak periods when it is most needed.

There is no need to place additional restrictions on qualifying for capacity payments, such as PG&E’s proposal to restrict capacity payments to QFs that meet resource adequacy requirements.²⁷ First, the CCC understands that the contribution of QFs to each IOU’s resource adequacy needs will be based on summer on-peak QF generation.²⁸ Both firm and as-delivered

²⁵ See D. 03-06-071, at pages 17 - 18.

²⁶ See D. 82-01-103, at 33 - 48.

²⁷ PG&E, at 5.

²⁸ See CPUC ALJ Michelle Cooke’s *Workshop Report on Resource Adequacy* (issued June 15, 2004) in R. 01-10-024, at 25 - 26.

QFs must operate at a high capacity factor during the summer on-peak period if they are to earn substantial capacity payments. Thus, the existing QF capacity payment structures – for both firm and as-delivered contracts – ensure that QFs that earn significant capacity payments are precisely those that contribute to meeting resource adequacy needs.

PG&E also makes a related argument that avoided capacity costs must be made on a \$ per kW basis, on the grounds that “these savings should be stated on the same basis that they are avoided.”²⁹ The utility opposes allocating these capacity costs to TOU periods and expressing them on a \$ per kWh basis. In terms of providing incentives to produce peak period power, one can achieve the same result with time-differentiated \$ per kWh capacity prices as with \$ per kW capacity prices plus performance standards. For example, if 100% of the capacity value is assigned to the summer on-peak period, then it makes little difference whether that value is paid based on the basis of \$ per kWh delivered in that period or on \$ per kW with a performance standard – in both cases the generator will face a substantial incentive to maximize summer on-peak production. There is nothing that prevents time-differentiated \$ per kWh prices from providing generators with the correct incentives to deliver power when they avoid capacity-related costs. Perhaps PG&E’s real complaint is that the current capacity allocation factors or TOU periods are not correct; if that is the case, then this proceeding will provide PG&E with the chance to amend those factors.

Another alternative that the CCC supports would be for the Commission to require the IOUs also to offer five-year, firm capacity, Standard Offer No. 2 contract to QFs whose original contracts have expired, in addition to the five-year SO1 contracts approved in D. 04-01-050. QFs under firm capacity SO2 contracts are paid for capacity on a \$ per kW basis with strong performance standards, which PG&E appears to prefer. Many cogeneration QFs have operated for the past 20 years under firm SO2 contracts, and the CCC expects that many such projects would elect a new SO2 contract to replace their original contracts when they expire. This step

²⁹ PG&E, at 7.

would provide new standard offer contracts tailored for QFs that offer either firm capacity (SO2) or as-available capacity (SO1).

VII. Conclusion

The CCC appreciates the Commission's attention to these reply comments on avoided cost issues. The CCC looks forward to continuing to advance these issues in the upcoming workshop and in subsequent phases of this important proceeding.

Respectfully submitted,

Jerry R. Bloom, Esq.
Joseph M. Karp, Esq.
White & Case, LLP
Three Embarcadero Center, Suite 2210
San Francisco, CA 94111
Telephone: (415) 544-1100
Facsimile: (415) 544-0202
E-mail: jrbloom@whitecase.com
jkarp@whitecase.com

R. Thomas Beach
Patrick G. McGuire
Crossborder Energy
2560 Ninth Street, Suite 316
Berkeley, California 94710
Telephone: 510-649-9790
Facsimile: 510-649-9793
E-mail: tomb@crossborderenergy.com
patrickm@crossborderenergy.com

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