

**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
Short-run and Long-run Avoided Costs,
Including Pricing for Qualifying Facilities.

Rulemaking 04-04-025
(Filed April 22, 2004)

PREHEARING CONFERENCE STATEMENT OF
THE CALIFORNIA COGENERATION COUNCIL,
THE CALIFORNIA WIND ENERGY ASSOCIATION, AND
THE CALIFORNIA BIOMASS ENERGY ALLIANCE, L.L.C.

W. Phillip Reese
California Biomass Energy Alliance, L.L.C.
915 L Street
Sacramento, CA 95814
Telephone: (916) 386-4343
Facsimile: (916) 386-4388
phil@reesechambers.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
tomb@crossborderenergy.com
patrickm@crossborderenergy.com

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

Attorneys for the California
Cogeneration Council and
the California Wind Energy Association

November 3, 2004

Received

NOV 03 2004

85827

Public Utilities Commission
Mailroom

**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
Short-run and Long-run Avoided Costs,
Including Pricing for Qualifying Facilities.

Rulemaking 04-04-025
(Filed April 22, 2004)

PREHEARING CONFERENCE STATEMENT OF
THE CALIFORNIA COGENERATION COUNCIL,
THE CALIFORNIA WIND ENERGY ASSOCIATION, AND
THE CALIFORNIA BIOMASS ENERGY ALLIANCE, L.L.C.

I. INTRODUCTION

In accordance with the October 22, 2004, Administrative Law Judge's Ruling Setting Prehearing Conference ("Ruling"), the California Cogeneration Council ("CCC"),¹ the California Wind Energy Association ("CalWEA"),² and the California Biomass Energy Alliance, L.L.C. ("CBEA")³ (jointly "QF Parties") hereby submit this prehearing conference statement. In this statement, the QF Parties, representing more than 3,650 MW of operating

¹ The CCC is an *ad hoc* association of natural gas-fired cogenerators located throughout California, in the service territories of all three of California's major investor-owned electric utilities ("IOUs"). CCC members are qualifying facilities ("QFs") under the Public Utilities Regulatory Policies Act of 1978 ("PURPA"). CCC members have sold their power to the IOUs for many years pursuant to contracts and avoided cost rates established by this Commission. In the aggregate, CCC members' QF projects generate roughly 2,700 MW in California.

² 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.

³ 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. In addition, the CBEA includes the Kramer Junction and Sunray Energy solar-thermal 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-two of the 30 CBEA plants are operating under the current five-year fixed price

QF capacity in California, identify the issues to be addressed in this proceeding, propose a schedule for addressing them and discuss the need for hearings. As requested in the Ruling, also attached hereto is a chart showing all of the avoided cost inputs and methodologies used by the Commission, including the specific information sought in the Ruling.⁴ Finally, a brief history of the evolution of the Commission's short-run avoided cost ("SRAC") pricing methodology is also attached.⁵

II. DISCUSSION

1. The Commission Should Bifurcate This Proceeding Into An SRAC Phase And An LRAC Phase.

The pre- and post-workshop comments of the parties have demonstrated a strong consensus for separating this proceeding into two distinct phases: one to address the SRAC prices used in paying QFs under standard offer contracts, and the other to address long-run avoided cost ("LRAC") pricing matters, which may have multiple applications, including for QF payments under new long-term QF contracts. There are a number of sound reasons to bifurcate the proceeding in this way. Most importantly, it will allow the subset of parties interested in SRAC matters to focus on the unique legal (e.g., Public Utilities Code Section 390) and technical issues affecting SRAC pricing.

A. Issues For The SRAC Phase.

The SRAC phase of this proceeding should consider the following four issues: (i) whether there is a need to revise the Commission's current SRAC energy price formula, including existing time-of-delivery ("TOD") and line loss factors; (ii) if there is a need to

agreements. In aggregate, CBEA members' operating QF projects in California provide 725 MW to the IOUs.

⁴ See Attachment A.

⁵ See Attachment B.

revise the current SRAC energy price formula, what changes should be made; (iii) establishing a renewed fixed price option for QFs upon expiration of the current five-year energy pricing amendments; and (iv) updating current as-available and as-delivered capacity prices. Each of these issues is discussed briefly below.

(i) Is there a need to revise the current SRAC energy price formula?

It is no secret that both Pacific Gas & Electric Company (“PG&E”) and Southern California Edison Company (“Edison”) have asserted, in the context of the Commission’s decisions to extend SO1 contracts to QFs whose contracts have or will soon expire, that the current SRAC formula is in need of revision.⁶ The Commission itself has expressed concern that the current SRAC formula may yield prices in excess of spot market prices during some hours of the day.⁷ Despite the complaints of the utilities and their reliance on short-term comparisons between SRAC prices paid to QFs and published spot market prices, the Commission has concluded that it has not been shown that the current SRAC price formula fails to track the IOUs’ avoided costs.⁸ One of the expressly stated purposes of this proceeding is to consider if, indeed, the current SRAC energy pricing formula fails to reflect short-run avoided costs and is in need of revision.⁹

(ii) If the SRAC energy price formula needs revision, what revisions should be made?

In considering potential changes to the current SRAC energy price formula, it is important to recognize that Public Utilities Code Section 390 (“Section 390”) does impose constraints upon the SRAC formula, but that these constraints are neither all-encompassing nor completely inflexible. As the CCC pointed out in its June 4, 2004 Pre-Workshop Opening Comments in this proceeding (at page 18), the Commission has already modified

⁶ See, e.g., D.04-01-050, at 137; D.03-12-032, at 57.

⁷ D. 03-12-032 at 57-58.

⁸ D. 04-07-037, at 6-7.

⁹ R.04-05-025.

the original Section 390 SRAC formula in Edison's territory to function much as the prior formula did, with a specific heat rate (Incremental Energy Rate, or IER), natural gas price, and O&M adder. In addition, there are a number of SRAC parameters that could (and perhaps should) be examined beyond those specifically directed under Section 390. These include TOD and line loss factors, which are applied to the Section 390 SRAC energy price formula to yield actual SRAC prices.

(iii) The Commission should establish a renewed fixed price option for QFs upon expiration of the current five-year pricing amendments.

In the midst of the 2000-2001 energy crisis, the Commission sought to stabilize QF pricing and generation by adopting, among other things, a per-se reasonable fixed energy price for QFs of 5.37 cents/kWh for a term of five years.¹⁰ As the Commission stated, this option was designed "to help bring stability to the electricity supply contracts"¹¹ between QFs and utilities and to "ensure that QFs generate as much electricity as reasonably possible, and at reasonable prices."¹² Of particular benefit from this option was that 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."¹³ This fixed price option was employed by numerous QFs, both renewable and cogeneration 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 QFs, the five-year period began in May of 2002 and will end in April of 2007. Upon expiration of the Fixed Price Amendments, QF pricing will resort to the Commission's prevailing SRAC formula.

As discussed in CalWEA's June 4, 2004 pre-workshop opening comments in this proceeding (at pages 2-3 and figures 1 and 2), the fixed price option has been an unqualified success. It has protected ratepayers against price volatility and has resulted in reasonable QF

¹⁰ D.01-06-15, at 4.

¹¹ D.01-09-021, at 3.

¹² D.01-06-015, at 3.

¹³ *Id.* at 4.

prices. This month provides an excellent example of the hedge that the fixed price option has provided, as California border gas prices in excess of \$7/MMBtu are producing posted SRAC prices for November in the range of \$75 to \$91/MWh. The fixed price is expected to result in savings to ratepayers as compared to SRAC prices during the relevant five-year period. It has also provided needed price stability for QFs, many of which are renewable and whose costs are unrelated to gas price fluctuations, and shielded them from regulatory uncertainty. The utilities also have benefited through the maximization of generation by existing resources. This maximization could prove essential as the utilities strive to meet the aggressive (and recently accelerated) reserve targets and Renewables Portfolio Standard (“RPS”) program mandates (which also may be accelerated). The Legislature, in SB 1078, recognized the value of these fixed price arrangements and sought to encourage their extension for a second five-year term in Public Utilities Code Section 390.1 (which is applicable to renewable QFs).

For these reasons, the QF Parties believe that the Commission should adopt a renewed five-year fixed price option for any QF that desires one. The option should be based upon forecasts of SRAC and should, for convenience, be available upon expiration of the existing five year fixed price agreements. The details of this mechanism, including the price, should be determined in this proceeding.

(iv) The Commission should update the IOUs’ current as-available capacity prices.

As shown on the chart attached hereto as Attachment A, there is a great disparity between the as-available (or as-delivered) capacity prices paid to QFs by the three IOUs. Although each of the IOUs derives its as-available capacity price from the costs of a combustion turbine, 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. The unreasonably low value for Edison is due entirely to the fact that the Commission traditionally set as-available capacity prices in the utilities’ Energy Cost Adjustment Clause (“ECAC”) proceedings, and there has not been an ECAC for Edison in many years.

Given that Edison has an identified need for capacity to meet its recently adopted reserve targets and to serve load, as evidenced by the order the Commission has just released advancing the resource adequacy deadline from 2008 to 2006, Edison's recent capacity solicitations, and the utility's acquisition of the Mountainview power plant, it is apparent that the as-available capacity price for Edison QFs should be based on the full cost of the combustion turbine. In light of the fact that Combustion Turbine ("CT") costs have recently been updated for use in the RPS proceeding and that Edison itself has proposed in its general rate case an updated CT value of \$78 per kW/year as basis for marginal generation capacity costs,¹⁴ it is reasonable to update the as-available capacity prices of each of the IOUs and Edison in particular. This issue is also discussed in the context of the avoided cost matrix set forth below.

B. Schedule For The SRAC Phase.

The QF Parties are prepared to move as quickly as the Commission deems appropriate in connection with the SRAC Phase. Two key scheduling parameters to consider at this time are (i) that the fixed price extension be completed in time for a seamless election upon expiration of the current fixed prices in June 2006 and April 2007 and (ii) that revising the as-available capacity prices proceed as quickly as possible, as Edison's price is clearly too low and is underpaying QFs in violation of PURPA.

The QF Parties believe that hearings will be required in connection with any revisions to the SRAC energy pricing formula. Experience has shown that SRAC proceedings are controversial and fact intensive. The QF Parties believe that hearings should not be required, however, in connection with revising as-available capacity prices. There is already a substantial body of work completed in connection with CT costs and capacity needs. In this respect, the Commission should solicit opening and reply comments on as-available capacity prices as soon as possible.

¹⁴ See Edison's Rebuttal Testimony in Phase II of A. 02-05-004, at page 16, lines 17-18.

C. Issues For The LRAC Phase.

In the LRAC phase of this proceeding, the Commission should, essentially, take the methodology set forth in the final E3 Report and adapt it as appropriate for each of the respective LRAC applications. Contrary to the positions of certain of the IOUs, if the Commission's LRAC methodology is a sound basis for one application, it should also be sound as the basis for other applications. Of particular concern to the QF Parties, naturally, is application of the E3 methodology to QF LRAC pricing.¹⁵ For QFs, the real question for this phase of the proceeding is which elements of the LRAC calculation outlined in the E3 Report should apply to QF LRAC pricing. While there is currently no express vehicle for a QF LRAC application, this is likely to change in the very near future.

In R.04-04-003, the Commission is about to embark upon consideration of a long-term approach to addressing the future of QFs with expiring standard offer contracts and of new QFs. These proposals will consider PURPA's must purchase obligation and ongoing state policy to encourage QFs. Pursuant to the September 30, 2004 ruling of Administrative Law Judge ("ALJ") Wetzell, parties will file proposals in that docket on November 10, 2004. The ALJ expects that a final Commission policy will be issued in the first quarter of 2005, if hearings are not required, and in the second quarter of 2005, if hearings are required. Appropriately, the Commission has expressly reserved to this avoided cost proceeding the development of LRAC, including for QF payments. As such, whatever the Commission adopts as its long-term policy for existing and new QFs not otherwise under contract, it will be for this proceeding to set the avoided cost prices.

D. Schedule For The LRAC Phase.

The Commission's current policy for QFs whose contracts expire (i.e., requiring the IOUs to enter into five-year SO1 contracts, as adopted in Decision 04-01-050) ceases to apply at the end of 2005. As such, it is critical that whatever is the Commission's long-term program for these QFs (and for new QFs), the program, including pricing, be fully operable

¹⁵ The CCC discussed at length in its pre- and post-workshop comments the propriety of applying the E-3 methodology in general to QF LRAC pricing, and the changes that should be made to the methodology, and the QF Parties will not repeat that discussion here.

on January 1, 2006. Given that QFs, like any business enterprise, need time for planning, it is highly desirable that the program be complete well before the end of 2005. Expedition is also warranted, as the Commission currently has no viable option for new QFs, other than participation in the current IOU procurement solicitations or one-off negotiation with the IOUs.¹⁶

For this reason, the QF Parties believe that the Commission should proceed expeditiously to refine the E3 methodology so that it is ready for application as QF LRAC pricing by the third quarter of 2005. Given that hearings likely will be required, this would require concurrent testimony (opening and rebuttal) to be submitted in January of 2005, hearings in February, briefs in March, a proposed decision in June and a final decision soon thereafter. The QF Parties are prepared to develop a precise schedule at the upcoming prehearing conference.

2. Avoided Cost Matrix.

The Ruling asks parties, as part of their PHC statements, to identify separately on a chart or spreadsheet all of the avoided cost inputs and methodologies “previously adopted or currently utilized” by the Commission, with citations to the relevant Commission decisions adopting those values or methods. With respect to current SRAC energy prices and as-available capacity prices, the QF Parties provide the requested information in the spreadsheet that is Attachment A to this statement. The QF Parties also provide, as Attachment B, a “Brief History of SRAC Pricing in California,” which includes a brief overview of the Commission’s SRAC methodologies since the outset of the QF program in the early 1980s, with citations to the key Commission orders along the way.


The Ruling also asks parties to note “the current schedule for updating these values, if any.” The QF Parties observe that posted SRAC energy prices are revised monthly to reflect changes in natural gas input prices. Going forward, the SRAC phase of this proceeding

¹⁶ Cogeneration QFs that meet IOU minimum size criteria are eligible to bid into only the IOUs’ generic solicitations. Renewable QFs are also able to bid into RPS solicitations, when issued and as subject to the various requirements of the RPS program including the availability of public goods charge funds.

should be the forum for litigating all prospective changes to SRAC pricing, so that all such changes to SRAC pricing can be reviewed in an integrated and consistent manner.

The Ruling also suggests that the Commission will entertain proposals to consolidate the approval and updating of values that the Commission uses across a wide spectrum of proceedings – such as the capacity value of a CT. The Ruling is correct that the CT value is used in many applications – for as-available QF capacity payments, for marginal generation capacity costs in electric revenue allocation, for the rate discounts for interruptible electric customers, for cost-effectiveness analyses of peak load reduction programs, and for setting the peaking Market Price Referent in the RPS program. As discussed above, it is also true that the CT values in use today vary widely. The QF Parties strongly support the Ruling's suggestion that the CT value should be revised regularly and posted on the Commission's website, in the same manner as are monthly as-available capacity prices for QFs. The Commission would use this posted value for a CT in all appropriate areas, unless a party could carry the burden of proof that such use is not warranted. Such a practice would bring greater consistency, accuracy, and timeliness to a variety of the Commission's ratemaking responsibilities.

Respectfully submitted,



Jerry E. Bloom
Joseph M. Karp
White & Case LLP¹⁷

Attorneys for the California Cogeneration
Council and California Wind Energy
Association

November 3, 2004

¹⁷ Counsel for CCC and CalWEA have been authorized to sign this document on behalf of the QF Parties.

Avoided Cost Parameters and Formulas

1. Currently Effective Methodology for SRAC Energy Pricing

SRAC Formula:

$$SRAC = \text{Starting SRAC} \times (1 - \text{Factor}) + \text{Factor} \times (\text{Monthly Border Gas Price} / \text{Starting Gas Price}) \times \text{TOU Allocation}$$

$$SRAC = (\text{Monthly Burner Tip Gas Price} \times \text{Heat Rate} + \text{O\&M Adder}) \times \text{TOU Allocation}$$

PG&E and SDG&E [1]
Edison [2]

| | PG&E Summer (May-Oct) | PG&E Winter (Nov-Apr) | Edison Summer (Jun-Sep) | Edison Winter (Oct-May) | SDG&E Summer (May-Sep) | SDG&E Winter (Oct-Apr) | Source | Frequency of Updates |
|----------------------------|-----------------------|-----------------------|-------------------------|-------------------------|------------------------|------------------------|--------------|--|
| Fixed Parameters | | | | | | | | |
| Starting SRAC (\$/MWh) | 18,748 | 23,973 | 20,808 | 20,808 | 22,181 | 22,181 | D. 96-12-018 | Used since October 1996. |
| Starting Gas (\$/MMBtu) | 1,4457 | 1,6394 | 1,3975 | 1,3975 | 1,3975 | 1,3975 | D. 96-12-018 | Used since October 1996. |
| Factor | 0.627 | 0.7875 | Formula [2] | Formula [2] | 0.605 | 0.605 | D. 96-12-018 | Used since October 1996. |
| Heat Rate or IER (Btu/kWh) | | | 9,140 | 9,140 | | | D. 01-03-067 | Used since April 2001. Same as Edison's 1994 - 1995 IER. |
| O&M Adder (\$/MWh) | | | 2.0 | 2.0 | | | D. 01-03-067 | Used since April 2001. Same as Edison's 1994 - 1995 O&M Adder. |

Natural Gas Input Variable

Midweek Border Prices Used
Malin Bidweek Indices - Average of:

| | 50% Malin, 50% Malin-Forward GD, NGI, NGW | 100% Malin-Forward NGI, NGW, BTU | 100% Malin-Forward NGI, NGW, BTU | D. 01-03-067 Publications [3] |
|-------------------------------------|---|----------------------------------|----------------------------------|--|
| Malin-Forward Adjustments | | | | |
| Monthly Bidweek Input Price | Malin | Malin | Malin | Monthly |
| plus PG&E System Transportation | 0.3597 | 0.3597 | 0.3579 | Publications [3] |
| plus PG&E System Shrinkage | 1.11% | 1.11% | 1.11% | PG&E G-AAOFF CGT Rate Cases |
| Edison Burner Tip Adjustments | | | | |
| Monthly Bidweek Input Price | NA | NA | Malin-Forward | Publications [3] |
| plus SoCalGas System Transportation | NA | NA | 0.3214 | PG&E Gas Rule 21 CGT Rate Cases |
| plus Municipal Surcharge | NA | NA | 1.46% WACOG [4] | SoCalGas GT-F5 BCAPs, Annual Adjustments |
| equals Monthly Gas Price | Topcock Equiv. | Topcock Equiv. | SCG Burner Tip | SoCalGas G-MSUR Monthly Updates |

D. 01-03-067 replaced the Topcock index with a Malin-forward index.

Monthly

Re-calculated Monthly

Fixed, except for monthly adjustments of the mid- or off-peak

TOU allocations in order to ensure a 1.0 average across all periods.

Per D.01-01-007, Energy Line Loss Factors are based upon the individual QF Generator Meter Multiplier (GMM), as calculated by the California ISO, divided by the system-wide GMM.

Notes

[1] Note that this formula is algebraically equivalent to the formula: SRAC = (Starting SRAC + Starting SRAC x [(Gas Price - Starting Gas Price)/Starting Gas] x Factor) x TOU Allocation

[2] From October 1996 to March 2001, the Edison formula had the same form as the PG&E and SDG&E formulas. In D. 01-03-067, the Edison's "Factor" fixed parameter was replaced with an algebraic formula, such that the Starting SRAC, and Factor terms are algebraically canceled out, and the Edison formula takes the form shown here.

[3] Gas Publications are Gas Daily (GD), Natural Gas Intelligence (NGI), Natural Gas Week (NGW), and BTU Weekly (BTU).

[4] In setting the municipal surcharge, the monthly SoCalGas WACOG is multiplied by 0.014828 x 0.985172, or about 1.46%.

[5] The TOU allocation factors for PG&E and Edison are set such that they average to 1.0 based on the number of subperiod hours in each month.

Per D.01-01-007, Energy Line Loss Factors are based upon the individual QF Generator Meter Multiplier (GMM), as calculated by the California ISO, divided by the system-wide GMM.

Notes

[1] Note that this formula is algebraically equivalent to the formula: SRAC = (Starting SRAC + Starting SRAC x [(Gas Price - Starting Gas Price)/Starting Gas] x Factor) x TOU Allocation

[2] From October 1996 to March 2001, the Edison formula had the same form as the PG&E and SDG&E formulas. In D. 01-03-067, the Edison's "Factor" fixed parameter was replaced with an algebraic formula, such that the Starting SRAC, and Factor terms are algebraically canceled out, and the Edison formula takes the form shown here.

[3] Gas Publications are Gas Daily (GD), Natural Gas Intelligence (NGI), Natural Gas Week (NGW), and BTU Weekly (BTU).

[4] In setting the municipal surcharge, the monthly SoCalGas WACOG is multiplied by 0.014828 x 0.985172, or about 1.46%.

[5] The TOU allocation factors for PG&E and Edison are set such that they average to 1.0 based on the number of subperiod hours in each month.

Per D.01-01-007, Energy Line Loss Factors are based upon the individual QF Generator Meter Multiplier (GMM), as calculated by the California ISO, divided by the system-wide GMM.

Notes

[1] Note that this formula is algebraically equivalent to the formula: SRAC = (Starting SRAC + Starting SRAC x [(Gas Price - Starting Gas Price)/Starting Gas] x Factor) x TOU Allocation

[2] From October 1996 to March 2001, the Edison formula had the same form as the PG&E and SDG&E formulas. In D. 01-03-067, the Edison's "Factor" fixed parameter was replaced with an algebraic formula, such that the Starting SRAC, and Factor terms are algebraically canceled out, and the Edison formula takes the form shown here.

[3] Gas Publications are Gas Daily (GD), Natural Gas Intelligence (NGI), Natural Gas Week (NGW), and BTU Weekly (BTU).

[4] In setting the municipal surcharge, the monthly SoCalGas WACOG is multiplied by 0.014828 x 0.985172, or about 1.46%.

[5] The TOU allocation factors for PG&E and Edison are set such that they average to 1.0 based on the number of subperiod hours in each month.

Per D.01-01-007, Energy Line Loss Factors are based upon the individual QF Generator Meter Multiplier (GMM), as calculated by the California ISO, divided by the system-wide GMM.

Notes

[1] Note that this formula is algebraically equivalent to the formula: SRAC = (Starting SRAC + Starting SRAC x [(Gas Price - Starting Gas Price)/Starting Gas] x Factor) x TOU Allocation

[2] From October 1996 to March 2001, the Edison formula had the same form as the PG&E and SDG&E formulas. In D. 01-03-067, the Edison's "Factor" fixed parameter was replaced with an algebraic formula, such that the Starting SRAC, and Factor terms are algebraically canceled out, and the Edison formula takes the form shown here.

[3] Gas Publications are Gas Daily (GD), Natural Gas Intelligence (NGI), Natural Gas Week (NGW), and BTU Weekly (BTU).

[4] In setting the municipal surcharge, the monthly SoCalGas WACOG is multiplied by 0.014828 x 0.985172, or about 1.46%.

[5] The TOU allocation factors for PG&E and Edison are set such that they average to 1.0 based on the number of subperiod hours in each month.

Per D.01-01-007, Energy Line Loss Factors are based upon the individual QF Generator Meter Multiplier (GMM), as calculated by the California ISO, divided by the system-wide GMM.

Notes

[1] Note that this formula is algebraically equivalent to the formula: SRAC = (Starting SRAC + Starting SRAC x [(Gas Price - Starting Gas Price)/Starting Gas] x Factor) x TOU Allocation

[2] From October 1996 to March 2001, the Edison formula had the same form as the PG&E and SDG&E formulas. In D. 01-03-067, the Edison's "Factor" fixed parameter was replaced with an algebraic formula, such that the Starting SRAC, and Factor terms are algebraically canceled out, and the Edison formula takes the form shown here.

[3] Gas Publications are Gas Daily (GD), Natural Gas Intelligence (NGI), Natural Gas Week (NGW), and BTU Weekly (BTU).

[4] In setting the municipal surcharge, the monthly SoCalGas WACOG is multiplied by 0.014828 x 0.985172, or about 1.46%.

[5] The TOU allocation factors for PG&E and Edison are set such that they average to 1.0 based on the number of subperiod hours in each month.

Per D.01-01-007, Energy Line Loss Factors are based upon the individual QF Generator Meter Multiplier (GMM), as calculated by the California ISO, divided by the system-wide GMM.

Notes

2. Currently Effective Methodology for As-Available Capacity Pricing

As-Available or As-Delivered Capacity Prices

| | PG&E Summer (May-Oct) | PG&E Winter (Nov-Apr) | Edison Summer (Jun-Sep) | Edison Winter (Oct-May) | SDG&E Summer (May-Sep) | SDG&E Winter (Oct-Apr) | Source | Frequency of Updates |
|-------------------------------------|-----------------------------|-----------------------------|-------------------------------|-------------------------------|------------------------------|------------------------------|-------------------------------|-------------------------------|
| Source: | D. 97-03-017 | D. 97-03-017 | D. 96-12-051 | D. 96-12-051 | 1996 | 1996 | | Not updated since 1996 - 1997 |
| Combustion Turbine Price (\$/kW-yr) | 64.93 | 64.93 | 49.3 | 49.3 | 70.34 | 70.34 | | Not updated since 1996 - 1997 |
| Energy Reliability Index | 1.0 | 1.0 | 0.1 | 0.1 | 1.0 | 1.0 | | Not updated since 1996 - 1997 |
| Shortage Cost (ER) x CT Price) | 64.93 | 64.93 | 4.93 | 4.93 | 70.34 | 70.34 | | |
| On Peak (\$/MWh) | 64.209 | 0 | 6.80 | NA | 69.001 | 9.311 | | |
| Mid Peak (\$/MWh) | 17.210 | 8.2000 | 0.80 | 0.30 | 4.323 | 5.710 | | |
| Off Peak (\$/MWh) | 0.006 | 0.0510 | 0.00 | 0 | 0 | 0 | | |
| Super Off Peak (\$/MWh) | 0 | 0 | NA | 0 | 0 | 0 | | |
| Non-TOU (\$/MWh) | 5.713 | 1.5740 | 0.70 | 0.10 | 7.533 | 1.469 | D.82-01-203 (50% for non-TOU) | |

Capacity Allocation Factors [1]

| | | | | | | | | |
|----------------|--------|--------|--------|--------|-------|-------|--|--|
| On-Peak | 76.19% | NA | 71.68% | NA | 73.5% | 5.9% | | Not updated since late 1980s or early 1990s. |
| Mid-Peak | 2.38% | 21.25% | 12.40% | 14.24% | 5.9% | 15.6% | | |
| Off-Peak | 0.02% | 0.15% | 0.24% | 0.88% | 0.0% | 0.0% | | |
| Super Off Peak | 0.00% | 0.00% | 0.00% | 0.56% | 0.0% | 0.0% | | |
| Seasonal Total | 78.59% | 21.40% | 84.32% | 15.68% | 79.4% | 21.5% | | |

Notes

[1] Expressed as the percent of the annual payment allocated to each TOU period.

Attachment A

Attachment B

A Brief History of SRAC Pricing in California

R. Thomas Beach, Principal
Crossborder Energy

January 13, 2004

$$\text{SRAC Energy Price} = \text{Fuel Price} \times \text{IER Heat Rate} + \text{O\&M Adder}$$

I. The Formula

The above formula has been the basis for SRAC energy pricing in California since the initial implementation of PURPA in California in the early 1980s. Each element of the formula has a lengthy history of CPUC proceedings and decisions.

The formula reflects the fact that a fossil fuel – oil or natural gas – has always been the predominant marginal resource for producing electricity in California.

Since the outset of the QF program, SRAC energy prices have always been set on a prospective basis, without retroactive downward adjustments, in order to allow QFs to make operating decisions knowing the minimum price they will be paid. *D. 82-12-120, at 107.*

The components of the SRAC formula reflect costs averaged over periods from one month, at a minimum, to as long as several years. Thus, SRAC prices do not track IOU avoided costs on a day-to-day basis.

II. Fuel Price

Until the mid-1980s, fuel oil was the predominant marginal fuel. Avoided fuel costs were revised quarterly, based on the IOUs' actual costs.

When natural gas largely displaced fuel oil in the mid-1980s, the avoided fuel cost was based on the fully bundled tariffed rate that the electric IOUs paid to the gas IOUs for natural gas supplies for electric generation.

A Brief History of SRAC Pricing
January 13, 2004

With the implementation of the restructuring of the natural gas industry in the late 1980s, the electric IOUs began to buy their own gas supplies, with the gas IOUs providing only transportation and storage services. Unbundled gas commodity markets opened first in the producing basins and later at natural hubs along the major interstate pipelines, such as Topock, Arizona and Malin, Oregon. The natural gas trade press began to report price indices for these markets.

In 1991, the CPUC approved an "index methodology" to determine the avoided fuel cost, using published producing basin indices to track the electric IOUs' actual natural gas costs on a timely basis. SRAC postings changed from quarterly to monthly, to coincide with the reporting of monthly "bidweek" gas prices. *D. 91-10-039.*

From 1991 - 1996, the CPUC adjudicated numerous issues concerning the index method, as gas markets continued to develop and the electric IOUs' gas purchases became more diversified and complex. For example, the method was revised to include indices for the rapidly-growing California border markets at Topock and Malin. *D. 96-07-023.* The electric IOUs began to buy significant volumes in the border markets to take advantage of low border prices that resulted from the glut of pipeline capacity to California. Edison pressed the CPUC to use 100% Topock prices as the avoided fuel cost in the SRAC posting.

In 1995 and early 1996, it became clear that the California electric industry would be restructured. In an effort to simplify the transition to a restructured market in which electric market prices would set SRAC, and to reduce the contentiousness of the index method, the IOUs and QF parties agreed in early 1996 to move to simplified "transition formulas" to set SRAC prices until the PX market was functioning properly. These formulas were based on regressions of 1994 - 1995 SRAC prices versus border gas prices, and were driven entirely by changes in border gas prices. The formulas were codified in P.U. Code Section 390(b); the CPUC adopted the specific, agreed-upon formula values in *D. 96-12-018.* The Edison and SDG&E formulas used 100% Topock prices; the PG&E formula reflected a 50/50 mix of Malin and Topock prices.

When border prices spiked during the 2000 - 2001 energy crisis, the Commission in *D. 01-03-067* replaced the Topock index with the Malin index plus an off-system transportation rate over the PG&E system.

III. The Incremental Energy Rate (IER) – a Heat Rate in Btu per kWh

The IER is intended to reflect the efficiency with which the IOUs could obtain the energy that they would have to produce (or purchase) “but for” QF production.

Traditionally, IERs have been calculated through complex production cost computer modeling of the IOU systems both with and without QFs, and have generated issues that have been difficult, at best, for the Commission to adjudicate.

The general formula for the IER has been:

$$\text{IER} = \{ (\text{QF}_{\text{OUT}} \text{ Costs} - \text{QF}_{\text{IN}} \text{ Costs}) / \text{QF Energy} \} / \text{Avoided Fuel Cost}$$

The IER is expressed in units of Btu per kWh, as follows:

$$\begin{aligned} \text{IER} &= \{ (\text{Costs in } \$) / (\text{QF Energy in kWh}) \} / \text{Fuel Costs in } \$ \text{ per Btu} \\ &= \{ (\$ / \text{kWh}) / (\$ / \text{Btu}) \} = \text{Btu} / \text{kWh} \end{aligned}$$

IERs do reflect the fact that fossil generation is not always on the margin.

IERs increase as demand increases, as less efficient plants are needed to supply the marginal kWhs. IERs also increase if production decreases from infra-marginal resources such as hydro or nuclear plants. The converse is also true.

IERs were originally determined in general rate cases. In the late 1980s, the Commission moved IER issues to annual ECAC cases. *D. 88-03-026*. Due to the complexity of IER issues, the IOUs, ORA, and QF parties tended to settle IER issues outside of the hearing room, with the Commission approving those agreements.

Commission-adopted IERs have been consistently in the range of 9,000 to 10,000 Btu per kWh over the two decades of the California QF program. IERs are time-differentiated according to each IOU’s time-of-use (TOU) periods.

The SRAC transition formulas approved in 1996 are based on regressions of 1994 - 1995 SRAC prices, and thus have 1994 - 1995 IERs implicit in them.

Historical Edison Heat Rates and O&M Adders

| <u>Year</u> | <u>Heat Rate</u> <i>Btu/kWh</i> | <u>O&M Adder</u> <i>¢/kWh</i> | <u>Fuel</u> <i>\$/MMBtu</i> |
|----------------|------------------------------------|--------------------------------------|--------------------------------|
| 1981 | 10,098 | 0.20 | 6.68 |
| 1982 | 9,979 | 0.20 | 5.72 |
| 1983 | 9,972 | 0.20 | 4.69 |
| 1984 | 9,961 | 0.20 | 4.60 |
| 1985 | 9,984 | 0.20 | 4.27 |
| 1986 | 9,984 | 0.20 | 2.97 |
| 1987 | 9,984 | 0.20 | 2.67 |
| 1988 | 9,773 | 0.30 | 2.88 |
| 1989 | 9,763 | 0.30 | 3.13 |
| 1990 | 9,689 | 0.30 | 3.11 |
| 1991 | 9,549 | 0.30 | 2.70 |
| 1992 | 9,012 | 0.30 | 2.98 |
| 1993 | 9,453 | 0.30 | 3.07 |
| 1994 | 9,170 | 0.21 | 2.52 |
| 1995 | 9,140 | 0.20 | 2.03 |
| 1996 | 9,428 | 0.16 | 2.30 |
| 1997 | 9,939 | 0.23 | 3.03 |
| 1998 | 9,982 | 0.23 | 2.72 |
| 1999 | 10,205 | 0.23 | 2.76 |
| 2000 | 10,357 | 0.23 | 5.32 |
| 2001 | 9,462 | 0.21 | 7.42 |
| 2002 | 9,140 | 0.20 | 3.59 |
| 2003 | 9,140 | 0.20 | 5.68 |
| Average | 9,703 | 0.23 | 3.78 |

Source: SCE Quarterly or Monthly SRAC Postings

IV. The O&M Adder

This component is designed to capture the IOUs' generating costs (except for fuel and capital costs) that vary with the amount of power purchased from QFs.

Historically, these costs have been limited to consumables such as chemicals and lubricants and to O&M costs that vary with the amount of power produced in IOU-owned gas-fired power plants (such as the costs of certain maintenance activities that are scheduled based on plants' production or operating hours, as well as the O&M costs avoided if QF power allows an IOU to place older units on standby).
D. 89-09-093.

Commission-adopted O&M adders have ranged from \$1 to \$3 per MWh. D. 01-03-067 adopted an O&M adder of \$2 per MWh for Edison.

Variable generating costs today also include air emission credit costs and periodic costs to replace expensive catalysts in air emission control equipment. FERC has adopted a variable O&M cost of \$6 per MWh in the California refund cases.

V. Moving SRAC to Electric Market Prices

The market-clearing price in the large PX market clearly represented the IOUs' avoided cost for QF generation, due to the requirement that the IOUs' purchase all of their power out of the PX market.

IOU avoided costs today are much less clear, given the much smaller, remnant wholesale electric markets now operating in California. There is no transparent, day-ahead electric market on which QF operating decisions could be based.

Daily electric market prices are much more volatile than gas-based, monthly SRAC prices. The IOUs can, and do, hedge their exposure to gas-based SRAC prices.

VI. As-Available Capacity Prices

Since the early 1980s, the Commission has directed the IOUs to base as-available capacity payments to QFs on the annualized costs of a combustion turbine (CT). The Commission has used the costs of a CT as the proxy for the value of capacity, because it represents the IOUs' least-cost source of pure capacity. *D. 82-01-103*, *D. 82-04-071*, and *D. 82-12-120*. For the past several decades, the Commission also has used CT costs to set marginal capacity costs for electric rate design.

The annualized costs of a CT (in \$ per kW-year) are allocated to time-of-use periods using capacity allocation factors, then converted to as-available capacity prices (in \$ per kWh) by dividing by the hours in each TOU period.

In the late 1980s, the Commission began to adjust CT costs downward using an Energy Reliability Index (ERI), to reflect the lower value of capacity in periods when the IOUs were long on capacity. The ERI varies between a minimum of 0.1 and a maximum of 1.0.

The Commission has not reviewed or adjusted QF as-available capacity prices since the mid-1990s. The CT costs and ERIs now in place vary widely among the IOUs.

QF As-Available Capacity Prices

| | <u>PG&E</u> | <u>Edison</u> | <u>SDG&E</u> |
|--|-----------------|---------------|------------------|
| Combustion Turbine Cost (\$/kW-yr) | \$63.90 | \$49.30 | \$70.34 |
| Energy Reliability Index (ERI) | 1.0 | 0.1 | 1.0 |
| As-Available Capacity Price (\$/kW-yr) | \$63.90 | \$4.93 | \$70.34 |

Last revised: D. 93-03-017 D. 96-12-056 1996

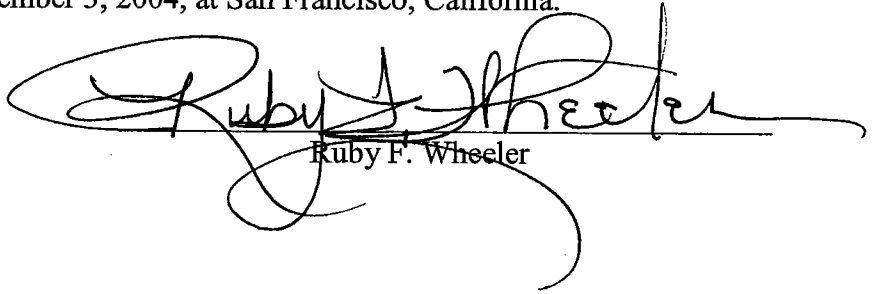
Certificate of Service

I hereby certify that I have this day served a copy of the

***PREHEARING CONFERENCE STATEMENT OF THE CALIFORNIA COGENERATION
COUNCIL, THE CALIFORNIA WIND ENERGY ASSOCIATION, AND THE
CALIFORNIA BIOMASS ENERGY ALLIANCE, L.L.C.***

On all known parties to R.04-04-025 by mailing a properly addressed copy by first-class mail
with postage prepaid to each party named in the official service list.

Executed on November 3, 2004, at San Francisco, California.



Ruby F. Wheeler