Decision 05-02-040 February 24, 2005

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company for Adoption of its 2005 Energy Resource Recovery Account (ERRA) Forecast Revenue requirement and for Approval of its 2005 Ongoing Competitive Transition Charge (CTC) Revenue Requirement and Rates. (U 39 E)	Application 04-06-003 (Filed June 1, 2004)

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Downey Brand LLP, by Ann L. Trowbridge, Attorney at Law, for Merced Irrigation District; and Joy Warren, Attorney at Law, for Modesto Irrigation District, interested parties.
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OPINION ON PACIFIC GAS AND ELECTRIC COMPANY'S ENERGY RESOURCE RECOVERY ACCOUNT

I. Summary

This decision adopts a 2005 Energy Resource Recovery Account (ERRA) forecast revenue requirement of $2.14 billion and a 2005 Competitive Transition Charge (CTC) revenue requirement of $23 million for Pacific Gas and Electric Company (PG&E). This decision also approves associated changes to PG&E's generation and ongoing CTC rates, including the establishment of sub-accounts for its Modified Transition Cost Balancing Account (MTCBA).

II. Background

PG&E filed its application in response to Commission directives in Decision (D.) 02-10-062 and D.02-12-074. Those decisions established ratemaking mechanisms to enable California investor-owned electric utilities to resume purchasing electric energy, capacity, ancillary services, and related hedging instruments.

D.02-10-062 established an ERRA balancing account for the major energy utilities to track fuel and purchased power revenues against actual recorded costs.[1] This balancing account was modeled after the Energy Cost Adjustment Clause (ECAC) balancing account. D.02-12-074 modified and clarified the cost recovery mechanisms adopted in D.02-10-062.

Subsequently, D.04-01-050, dated January 22, 2004 adopted a June 1, 2004 application date for PG&E's 2005 ERRA forecast and a February 2005 date for its 2004 reasonableness application. The purpose of PG&E's annual ERRA forecast application is to address its energy resource forecast for the upcoming twelve months and a new ERRA rate based on that forecast.

III. Discussion

By its application, PG&E requested approval of its 2005 ERRA forecast revenue requirement of $2.14 billion, 2005 ongoing Competition Transition Charge (CTC) of $23 million, and associated changes to PG&E's generation and ongoing CTC rates. PG&E also requested Commission approval for a routine amortization of the year-end balances in its ERRA and MTCBA.

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[1] PG&E, Southern California Edison Company, and San Diego Gas & Electric Company were identified as the major energy utilities.

IV. Evidentiary Hearing

Issues litigated in this proceeding between PG&E and the Office of Ratepayer Advocates (ORA), Merced Irrigation District (Merced ID) and Modesto Irrigation District (Modesto ID) related to rate design and CTC.

Although Modesto ID took exception to PG&E's requested 90-day amortization of ERRA and MTCBA year-end balances, PG&E modified that proposal to a twelve-month amortization period as part of its updated testimony.[2] PG&E also clarified that it would seek approval of amortizing any ERRA and MTCBA year-end 2004 balance through an advice letter filing.[3] Hence, the amortization dispute between PG&E and Modesto ID in this proceeding is moot.

A. Rate Design Issue

PG&E proposed to implement generation revenue requirement changes as a percentage change to each bundled service generation rate component of each rate schedule after the current generation component is adjusted for the ongoing CTC rate. After determining the individual ongoing CTC and generation rates for each rate schedule, total rates would be determined by adding the current rates that would not change, such as nuclear decommissioning and public purpose programs, and the proposed rates for generation and ongoing CTC.

PG&E proposed to modify its residential customers' rate design due to its perceived constraint on total residential charges for usage up to 130 percent

[2] Exhibit 5, p. 10-1.

[3] Reporter's Transcript, Vol. 1, p. 74.

(%) of baseline. That is, in the residential class, total charges for Tier 1 and Tier 2 usage could not be increased on the basis that Water Code Section 80110, adopted as part of AB 1x in January 2001, prohibits increases to total rates for residential usage less than 130% of baseline until the California Department of Water Resources (DWR) has recovered the costs of power it has procured for PG&E's retail end use customers.

Although the overall allocation to the residential class would be a reduction, PG&E opposed any reduction to Tier 1 and Tier 2 rates because those residential classes were allocated a relatively small proportion of the generation surcharges levied in 2001. PG&E also opposed reductions in its Tier 1 and Tier 2 rates until the allocation of generation revenue among all classes has been fully evaluated in its Phase 2 general rate case (GRC) proceeding, A.04-06-024. Therefore, PG&E proposed to hold its Tier 1 and Tier 2 rates constant and allocate the revenue requirement changes applicable to Tier 1 and Tier 2 to its Tier 3 and Tier 4 end users.

ORA opposed PG&E's Tier 1 and Tier 2 rate design proposal on the basis that it deviates from the currently adopted cost allocation method. ORA recommended that PG&E's proposal should be considered in its GRC proceeding because it modifies a rate design mechanism.

PG&E's proposal does not deviate from its post-bankruptcy Rate Design Settlement Agreement (RDSA), which requires PG&E to allocate changes to the revenue requirement for a particular component based on the rate schedule's share of revenue for that component based on present rates.[4] Its

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[4] D.04-02-062, RDSA *mimeo.*, p. 5.

proposal is also consistent with recent overall electric rate reductions.[5] Hence, PG&E's proposal should be adopted.

PG&E should not allocate to Tier 1 and Tier 2 any residential reduction, or increase. Consistent with past practice, any change in revenue allocated to the residential class should be reflected in changes to Tier 3 and Tier 4 rates. PG&E should use the memorandum account established by Resolution E-3906 collected from Tier 3 and Tier 4 rates resulting from PG&E holding Tier 1 and Tier 2 rates constant in this proceeding, with such amounts considered for potential reallocation among customer groups in PG&E's General Rate Case rate design phase. Revenue decreases associated with reducing residential Tiers 3 and 4 rate should be tracked separately from those revenues currently being tracked in its existing memorandum account.

PG&E also proposed to establish subaccounts in its MTCBA to more precisely track costs, revenues, and over- or undercollections uniquely applicable to individual customer groups. Those individual customer groups are Direct Access and Bundled, Municipal Departing Load, and Customer Generation Departing Load. There is no opposition to this proposal. PG&E should submit an advice letter filing setting out the appropriate tariff language to implement these subaccounts in its MTCBA for Commission review and approval.

B. CTC Issues

There are two contested CTC issues in this proceeding. The first issue is the inclusion of qualifying facilities (QF) restructuring costs in the ongoing

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[5] For example, see D.04-02-062, dated February 26, 2004 and Advice Letter 2515-E, approved on July 22, 2004.

CTC calculation. The second issue is the appropriate long-term gas price forecast for use in the ongoing CTC benchmark.

1. QF Restructuring Costs

PG&E included $21 million of QF restructuring costs associated with the buy-out, buy-down, or renegotiation of QF contracts as an addition to its ongoing CTC calculation. PG&E testified that the full cost of restructuring QF contracts is recoverable as an ongoing CTC and thus, not included in the above-market portion of the CTC calculation. They are included as an adder to the ongoing CTC.[6] Merced ID and Modesto ID disagreed.

Merced ID and Modesto ID alleged that PG&E's 2005 ongoing CTC revenue requirement and rates must be recalculated to exclude restructuring contract costs of $21.0 million because of the requirements in Sections 367(a)(2) and 367(b) of the Public Utilities Code.[7] Modesto ID believes that the restructuring costs may be collected to the extent they meet the following conditions: (1) the restructured contract was CTC-eligible, (2) the restructure does not extend the contract term, and (3) the restructure costs are netted against the benchmark. Modesto ID added that the statutory provisions require the same treatment for any CTC eligible restructure costs and the underlying contract costs. Modesto ID concluded that PG&E's proposed treatment of the $21 million restructuring costs is inconsistent with the law on the basis that the amount was not netted against the benchmark.

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[6] Exhibit 1, p. 7-4.

[7] All statutory references are to the Public Utilities Code unless otherwise stated.

Modesto ID joined Merced ID's conclusion that under Section 367(b), restructured QF contract costs are to be treated like other QF contract costs, that is, PG&E is required to net such costs against market benchmark and may only collect above market costs as Tail CTC.[8] Under Section 367(b), while the above and below market costs associated with the original term of restructured QF contracts may be included in PG&E's Tail CTC revenue requirement, the full costs may not be included as an adder to the ongoing CTC. Merced ID added that PG&E should limit its Tail CTC revenue requirement to the above and below market costs associated with the original term of such contracts and that the full costs may not be included.[9]

PG&E responded that QF restructuring contract costs are recorded under its MTCBA preliminary statement as ongoing CTC in their entirety and that there are no kilowatt-hours (kWh) associated with the costs in question. Therefore, PG&E believes that there is no "market" component to these costs and no basis for excluding them from its estimate of 2005 ongoing CTC costs. We concur with PG&E. The $21 million QF restructuring costs should be included as a component of the 2005 ongoing CTC costs.

2. Long-Term Gas Price Forecast

One of the issues litigated in the 2004 ERRA proceeding is the method for establishing the benchmark to be used for the ongoing CTC calculations. To the extent that a generic methodology for establishing the "market" benchmark to be used for the ongoing CTC calculation is adopted in

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[8] Merced ID opening brief, p. 5.

[9] *Id.*

the 2004 proceeding, the parties are concerned that a different benchmark may need to be established for the 2005 calculation.

Not knowing the outcome of the 2004 ERRA decision with respect to determination of the benchmark used in the ongoing CTC calculation, parties litigated one benchmark-related issue in this proceeding. That issue is whether the gas price forecast incorporated into the California Energy Commission's (CEC) levelized generation cost calculations should be updated, and if so, how.

To the extent that the 2004 ERRA decision addresses the issue, the parties concurred that it should not be relitigated in this proceeding. If, for example, the 2004 ERRA decision required the ongoing CTC benchmark to be based on the CEC's latest available calculation, without modification, that would moot out the gas price update issue litigated by the parties in this proceeding. If, on the other hand, the 2004 ERRA decision is not so clear on this point, the parties question whether the CEC calculations should be modified to incorporate a different forecast gas price benchmark in this 2005 ERRA proceeding.

PG&E proposed to use a benchmark price of $52.15 per megawatt-hour (MWh) based on a CEC model that included the CEC's most recent gas price forecast with a twenty-year levelized gas price based on a 2005 gas price of $4.97per million British thermal units (MMBtu). Modesto ID proposed alternative gas price forecasts. The first method used PG&E's 2005 gas price forecast of $5.827 per MMBtu from PG&E's second phase general rate case proceeding and applied it for twenty years. The second method resulted in a benchmark price of $71.78/MWh based on a comparison of the CEC's 2005 gas price forecast to PG&E's second phase GRC proceeding and application of the resulting ratio to all of the CEC's gas price estimates over the long term.

There was no dispute that the gas price benchmark for use in the ongoing CTC calculations would be resolved in PG&E's 2004 ERRA forecast proceeding. By D.05-01-031 of that proceeding, a 5.18¢/kWh benchmark rate was adopted for 2004 based on a CEC model that included the CEC's most recent gas price 20-year forecast with a levelized cost of a gas-fired cycle generating unit. Similar to the adopted 2004 forecast, PG&E based its 2005 benchmark rate on a CEC model that included CEC's most recent gas price forecast with a 20-year levelized gas price. Modesto ID's alternative gas price forecasts deviate from the D.05-01-031 approved forecast method and should be rejected. PG&E's $52.15 MWh benchmark rate is consistent with the method adopted in D.05-01-031 and should be adopted.

Although Merced ID and Modesto ID filed applications for rehearing of D.05-01-031 on February 11, 2005, that decision was not stayed. Therefore, until the Commission may modify the method for establishing the market benchmark to be used for ongoing CTC calculations the method used in D.05-01-031 should continue to be used. If the Commission subsequently modifies D.05-01-031 in that regard, PG&E should include in its advice letter incorporating any modifications ordered to D.05-01-031 necessary changes in PG&E's 2005 market benchmark for ongoing CTC calculations. Any such change should be effective on the date that the decision modifying D.05-01-031 is issued.

C. 2005 ERRA Forecast

Not at issue was PG&E's 2005 ERRA revenue requirement forecast. Although individual components of the revenue requirement forecast were placed under seal, details of those components were made available to interested parties under a protective agreement.[10]

ORA scrutinized PG&E's testimony attached to the application. Based on that scrutiny, it concluded that PG&E's 2005 ERRA forecast based on its load, resources available to meet its load, fuel costs, and costs for the various resources adopted were reasonable. Neither Merced ID nor Modesto ID took issue with PG&E's 2005 ERRA forecast revenue requirement. The following tabulation summarizes the major components of its 2005 ERRA revenue requirement forecast.

ERRA Component	**Forecast** ($000s)
Fuel Costs	$ 148,730
New Power Purchase Contracts	323,441
QF & Purchased Power Agreements	1,647,086
Subtotal	2,119,257
Franchise Fees & Uncollectibles	20,349
Total Revenue Requirement	$2,139,606

We concur and adopt PG&E's 2005 ERRA forecast revenue requirement of $2.14 billion.

[10] Information deemed commercially sensitive and proprietary was placed under seal pursuant to a July 23, 2004 Administrative Law Judge ruling. All information placed under seal should remain sealed for a period of one year from the date of a final order in this proceeding, and during that period should not be made accessible or disclosed to anyone other than Commission staff except on the execution of a mutually acceptable protective agreement.

D. Prior CTC Issues

The CTC issues litigated in PG&E's 2004 ERRA forecast proceeding were pending resolution at the time an evidentiary hearing was held in this proceeding. These CTC issues included the method to calculate ongoing CTC costs for departing load customers, method to determine the ongoing CTC benchmark, and ongoing CTC-eligibility for QF power purchase agreement extension costs. Rather than relitigate these CTC issues in this proceeding, all parties concurred that PG&E should incorporate the Commission's ultimate resolution of these CTC issues into this proceeding.[11]

D.05-01-031 resolved the pending CTC issues, which was issued subsequent to the filing of briefs and prior to the issuance of a draft decision in this proceeding. The resolution of CTC issues in D.05-01-031 is consistent with PG&E's CTC position in this proceeding. Hence, the remaining 2004 CTC issues are moot until such time that the Commission may rule otherwise as a result of the applications for rehearing of D.05-01-031, which has not been stayed.

V. Procedural Matters

By Resolution ALJ 176-3135, dated June 9, 2004, the Commission preliminarily designated the captioned application as "ratesetting" with hearings indicated. Notice of the application appeared in the Commission's June 8, 2004, Daily Calendar. Since there is no objection to the ratesetting categorization of this proceeding, we affirm that this is a ratesetting proceeding.

[11] Reporter's Transcript Vol. 1, p. 6.

A Prehearing Conference held on July 20, 2004 and an evidentiary hearing on September 28, 2004. This matter was submitted upon receipt of reply briefs on October 22, 2004.

VI. Comments on Proposed Decision

The proposed decision of the ALJ in this matter was mailed to the parties in accordance with Pub. Util. Code § 311(d) and Rule 77.1 of the Rules of Practice and Procedure. Comments were filed on February 14, 2005, and reply comments were filed on February 22, 2005. To the extent changes were necessary as a result of the filed comments, they were made in the body of this order.

VII. Assignment of Proceeding

Michael R. Peevey is the Assigned Commissioner and Michael J. Galvin is the assigned Administrative Law Judge in this proceeding.

Findings of Fact

1. PG&E's application was filed in response to the Commission's directives in D.02-10-062 and D.02-12-074.

2. The inputs used to derive PG&E's 2005 forecasts are based on its load forecast, the forecast of resources to meet its load, and the costs of the various resources.

3. Details of PG&E's 2005 revenue requirement forecasts are set forth in the testimony attached to its application and testimony placed under seal.

4. D.05-01-031 found that QF restructuring costs are properly included as a component of the CTC calculation.

5. D.05-01-031 adopted a market benchmark rate for calculating CTC based on the CEC's most recent 20-year forecast with a levelized cost of a gas-fired cycle generating unit.

6. Merced ID and Modesto ID filed applications for rehearing of D.05-01-031.

7. The filing of applications for rehearing of D.05-01-031 did not stay that decision.

8. All parties agreed that CTC issues litigated in PG&E's 2004 ERRA forecast proceeding would not be relitigated in this proceeding and that the results of that proceeding would be incorporated into this proceeding.

9. PG&E's Tier 1 and Tier 2 rate design proposal is consistent with the currently adopted cost allocated method.

10. PG&E's Tier 1 and Tier 2 rate proposal is consistent with its post-bankruptcy RDSA.

11. PG&E and ORA concurred that PG&E's Tier 1 and Tier 2 rate design proposal could be re-evaluated in PG&E's GRC Phase 2 where it differed from current practice..

12. There is no opposition to PG&E's proposal to establish subaccounts in its MTCBA to more precisely track costs, revenues, and over- or undercollections uniquely applicable to individual customer groups.

13. PG&E included $21 million of QF restructuring costs as an addition to its ongoing CTC calculation.

14. There was no opposition to PG&E's 2005 ERRA forecast.

Conclusions of Law

1. The application should be granted to the extent addressed in the body of this order.

2. Information placed under seal should remain sealed because, if disclosed, it would provide competitors an insight to PG&E's energy procurement strategy and place PG&E and its ratepayers at a disadvantage in seeking future energy contracts.

3. Restructured QF contract costs should be included as a component of PG&E's 2005 ongoing CTC costs.

4. PG&E should implement rate changes in this proceeding consistent with the methods approved by the Commission in 2004.

5. PG&E should use its existing memorandum account established in compliance with Resolution E-3906 to track any revenue requirement changes resulting from PG&E holding its Tier 1 and Tier 2 rates constant, pending possible reallocation of that revenue in its GRC rate design phase.

6. PG&E may establish customer group subaccounts in its MTCBA.

7. D.05-01-031 resolved the pending 2004 CTC issues until such time that the Commission may rule otherwise as a result of the applications for rehearing of D.05-01-031.

8. This decision should be effective immediately so that PG&E can implement its 2005 ERRA forecast expeditiously.

O R D E R

IT IS ORDERED that:

1. The 2005 Energy Resource Recovery Account (ERRA) forecasts of Pacific Gas and Electric Company (PG&E) regarding its load, the resources available to meet its load, fuel costs, and costs for the various resources are adopted as set forth in the body and conclusions of law of this order.

2. PG&E's 2005 ERRA forecast revenue requirement of $2.14 billion and a 2005 ongoing Competitive Transition Charge revenue requirement of $23 million are adopted.

3. PG&E shall submit an advice letter proposing new rates to collect the revenue requirements adopted in the decision using the rate design adopted in

the decision, with such advice letter due at least 40 days in advance of the proposed effective date for such rates.

4. All information placed under seal shall remain sealed for a period of one year from the effective date of this order except upon the execution of a mutually acceptable nondisclosure agreement or on further order or ruling of the Commission or the Administrative Law Judge then designated as the Law and Motion Judge. If PG&E believes that further protection of sealed information is needed beyond one year after the effective date of this order, it may file a motion stating the justification for further withholding of the sealed information from public inspection, or for such other relief as the Commission may provide. This motion shall be filed no later than 30 days before the expiration of this ordering paragraph.

5. PG&E shall use its existing memorandum account in compliance with Resolution E-3906 to track any revenue requirement changes resulting from PG&E holding Tier 1 and Tier 2 rates constant, pending possible reallocation of that revenue in its general rate case rate design phase. Any such rate decrease shall be tracked separately in that memorandum account.

6. PG&E shall submit an advice letter filing within 45 days after the effective date of this decision setting out the appropriate tariff language to implement Direct Access and Bundled, Municipal Departing Load, and Customer Generation Departing Load subaccounts in its Modified Transition Cost Balancing Account for Commission review and approval.

7. Application 04-06-003 is closed.

This order is effective today.

Dated February 24, 2005, at San Francisco, California.

MICHAEL R. PEEVEY
President
GEOFFREY F. BROWN
SUSAN P. KENNEDY
DIAN M. GRUENEICH
Commissioners