May 25, 2000

ADVICE 2003-E

Public Utilities Commission of the State of California:

Pacific Gas and Electric Company (the Company) hereby submits for filing revisions to its electric tariff sheets. The affected tariff sheets are listed on the enclosed Attachment I.

The purpose of this filing is to request authorization to use and recover the costs of new daily and balance-of-the-month block forward market (BFM) contracts which the California Power Exchange (CalPX), via its California Trading Services Division (CTS), plans to offer starting June 29, 2000.the Company. In order to implement this request, the Company submits revisions to Schedule PX—*Power Exchange Energy Cost*.

Background

In its Federal Energy Regulatory Commission (FERC) May 2, 2000 filing, CalPX indicates that these two new services will increase the liquidity in the California and Western markets, and most likely will have a positive impact on its core CalPX Day-Ahead market. CalPX believes these services will attract new supply into the California market by allowing suppliers the opportunity to contract at fixed prices.

The new services will improve the Company's ability to manage risk by allowing it to diversify its exposure in the Day-Ahead market in the current delivery month. The ability to transact near-term power in the BFM should reduce the Company's risk in the Day-Ahead market and in the Independent System Operator (ISO) imbalance market.

CTS plans to offer the new products at all current locations for delivery between the hours of 6:00 a.m. and 10:00 p.m. Trading for the daily block will cease one day prior to delivery; trading for the balance-of-the-month block will cease two days prior to delivery. Participants in the new BFM market will pay volumetric fees for the total megawatts purchased or sold, and settlement fees for the net megawatts purchased or sold.

Proposed trading limits

In Resolution E-3658, the Commission authorized the Company to trade in the BFM in an amount equal to its net-short position. The Commission defined "net short position" to mean the hourly amount of demand averaged over the quarter by which the utility's bundled service exceeds the supply the utility provides in that hour, excluding previous block-forward purchases. The Company does not propose a change to its authority to use quarterly or monthly BFM services. However, because of the short-term nature of the new daily and balance of the month services, the Company requests that the trading limit for these new services be equal to its daily net position, taking into account daily changes in its load and resources. The Company proposes the daily net short position limit for each quarter and pricing zone be defined as the highest historical amount of bundled service demand, averaged over 16 hours (6 am to 10 pm) daily, by which such demand exceeds the supply the Company provides in those hours, less previous block-forward purchases, and adjusted for any major load and resource changes.[1] The Company proposes this limit to be in effect through the end of its rate freeze, or until changed by the expected Post-Transition Electric Procurement- Phase II decision.

Cost Recovery

Consistent with the cost recovery authorized for other BFM trades in Resolutions E-3618 and E-3658, the Company requests that the Commission find that the use of the new BFM daily and balance of the month services is considered *per se* reasonable. The Company should recover the cost of these new services without the need for reasonableness reviews through the end of its rate freeze.

The Company will record certain costs in the Block Forward Market Memorandum Account (BFMMA) incurred to participate in the new BFM services that are not billed to the Company by CalPX.

In order to enable the Company to use the new BFM contracts for Summer 2000, the Company respectfully requests that this filing become effective on **July 4, 2000**, which is 40 days after the date of filing.

[1] The Company believes that information about its hedged and unhedged position is commercially sensitive. If required, the Company will provide information about its historical net position to the Energy Division subject to PU Code Section 583.

This filing will not increase any rate or charge, cause the withdrawal of service, or conflict with any rate schedule or rule.

Anyone wishing to protest this filing may do so by sending a letter within 20 days of this filing. Protests should be mailed to:

IMC Branch Chief
Energy Division
California Public Utilities Commission
505 Van Ness Avenue, Room 4002
San Francisco, California 94102
Facsimile: (415) 703-2200

Copies should also be mailed to the attention of the Director, Energy Division (address above), and Les Guliasi, Regulatory Relations Manager, 77 Beale Street, Mail Code B10C, P.O. Box 770000, San Francisco, California 94177, Facsimile (415) 973-7451. The protest should set forth the grounds upon which it is based and shall be submitted expeditiously. There are no restrictions on who may file a protest.

In accordance with Section III, Paragraph G of General Order 96-A, the Company is mailing copies of this advice filing to the utilities and interested parties shown on the attached list. Address change requests should be directed to Nelia Avendano at (415) 973-3529.

Vice President – Regulatory Relations

cc: California Independent System Operator
California Power Exchange
Electricity Oversight Board

Attachments

SCHEDULE PX—POWER EXCHANGE ENERGY COST

APPLICABILITY: This schedule applies to customers who elect PG&E's Bundled, Direct Access and Hourly PX Pricing Option services.

TERRITORY: Schedule PX applies everywhere PG&E provides electric service as shown in Preliminary Statement, Part A.

RATES: This schedule will apply where calculation of the Power Exchange (PX) energy cost is required for either energy cost credits or charges. The PX cost used for billing will consist of the forward market cost plus settlement costs, adjusted by an allowance for uncollectibles and Distribution Loss Factors (DLFs). PG&E shall utilize the best information available for calculating the PX energy cost.

1. Development of hourly forward market costs:

   Hourly market clearing prices and loads, or the total costs allocated to PG&E by the PX, as a result of block forward, day-ahead, or hour-ahead scheduling of load in a PX-administered forward energy market will be obtained (or estimated to the extent feasible) for each relevant transmission pricing zone on the day following each trading day. Total costs for services obtained through the PX shall include, but are not limited to, the following:

   a. Energy, including inter-zonal congestion fees;
   b. Ancillary Services;
   c. Independent System Operator (ISO) and PX administration costs including subscription fees, payments, or charges by the PX, or CalPX Trading Services (CTS), as required by CTS trading rules and/or the Participation Agreement net of credits, rebates, or refunds; and
   d. Other miscellaneous ISO/PX charges incurred to serve Bundled Service Customers.

(Continued)

SCHEDULE PX—POWER EXCHANGE ENERGY COST
(Continued)

RATES: (Cont'd)

1. Development of hourly forward market costs (Cont'd)

   The weighted average cost for these services shall be calculated for each hour as the sum of the costs in the day-ahead market in each zone, plus the costs in the hour-ahead market in each zone, plus the net gain or loss on transactions in the block forward market, all divided by the total kWh purchased in all zones in all forward energy markets for that hour. PG&E's block forward market transactions shall be limited as defined in Resolution E-3658, and modified pursuant to (T) subsequent Commission decisions and resolutions. Furthermore, PG&E is (T) guaranteed recovery of costs for its block forward market transactions for deliveries until the end of PG&E's rate freeze.

2. Estimate of Real-time Settlement Costs:

   An estimate of real-time settlement costs for the trading day will be calculated hourly and added to the cost derived in Part 1 of this section on the trading day, or as soon thereafter as practicable. This rate is determined by dividing the estimate of the real-time cost amount, including spinning reserve, non-spinning reserve, replacement reserve, regulation, and imbalance energy, by PG&E's estimate of the load to be served by the PX.

3. Real-time Settlement Costs True-Up:

   A real-time settlement cost true-up, representing the real-time costs not yet reflected in charges to customers for the trading day 60 days or earlier, is added to the cost derived in Parts 1 and 2 of this section. This rate is determined by dividing the real-time cost amount (which is the dollar amount (either positive or negative) incremental to the cost described in Parts 1 and 2 of this section) by PG&E's estimate of the load to be served by the PX. Two adjustments may eventually be implemented: one for all customers of PG&E and an incremental adjustment only for customers without real-time meters.

   PG&E may make up to two real-time settlement cost true-ups on a single day's hourly prices, in order to shorten the lag between the real-time settlement cost true-up and the trading day.

(Continued)

SCHEDULE PX—POWER EXCHANGE ENERGY COST
(Continued)

RATES: (Cont'd.)

4. Post Real-Time Settlement Costs:

Adjustments for incentive payments made to customers taking service under Schedule E-BID, costs recorded in the E-BIDMA (Preliminary Statement Part BS), black start capability, long term voltage support, PX administration costs, ISO grid management charges, and amounts resulting from dispute resolution may be required after the real-time settlement cost adjustment is incorporated into PX prices. PX charges including, but not limited to, these adjustments which are available after the real-time settlement cost adjustment has been implemented for a specific hour, will be accrued once a month and applied to adjust PX prices in the next full calendar month. Once the total accrued amounts are summed, the total will be divided by the number of days in the next full calendar month to develop a daily amount. The daily amount will be divided by the sum of PG&E's estimate of the 24 hourly loads for the day to determine an adjustment ($/MW) for the day.

5. Adjustments for Distribution Loss Factors (DLFs) and Uncollectibles:

The average hourly cost at the transmission/distribution interface, as determined by the sum of the average costs described in Parts 1, 2, 3 and 4 of this section, is multiplied by the DLF and an uncollectible factor to determine the appropriate price to be paid by end-use customers served at each voltage level. DLFs will be calculated by PG&E based on the forecast hourly PG&E UDC Service Area Load (Direct Access, plus Bundled Service, including Hourly PX Pricing Option Service) per Decision 97-08-056. The hourly DLFs will be broken out by service voltage level and made available each day to market participants during the day-ahead market. PG&E will calculate the hourly DLFs based on samples of hourly service area load by applying the approach approved in Decision 92-12-057. The uncollectible factor is equal to 1.002456.

BUNDLED SERVICE OR DIRECT ACCESS SERVICE:

1. Calculation of PX charges for Bundled Service and Hourly PX Pricing Option Customers and PX credits for Direct Access and Hourly PX Pricing Option Customers:

For purposes of determining PX charges for Bundled Service Customers and the PX credit for Direct Access and Hourly PX Pricing Option Customers, an average for each schedule (or TOU period) is developed through the use of a statistical load profile which represents the average load profile for all customers (both Direct Access and Bundled Service) on a given rate schedule. For Agricultural, Traffic Control, Streetlighting, and Outdoor Lighting rate schedules, the statistical load profiles are "static" and are determined hourly for the entire year based on average historical data for three recorded years. These latter static statistical load profiles are updated each calendar year based on available data for the previous three years. For all remaining rate schedules, the statistical load profile is determined "dynamically," using the most current load research information available. This current data will become available and will be posted approximately seven days from the date of occurrence.

The sum of the products of the (1) average hourly costs, including adjustments, and (2) the hourly loads, divided by the use associated with the statistical load profile (expressed as a fraction of the profile period use allocated to each hour) will yield an average cost for a specific customer group and TOU period. These average PX costs will be updated weekly.

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