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Decision 98-06-076 June 18, 1998

ORIGINAL

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company for an Order Under Section 701 of the Public Utilities Code Granting Pacific Gas and Electric Company Permission to Use Natural Gas-Based Financial Instruments to Manage the Impact of Natural Gas Prices on the Cost of Electricity Under Existing Power Purchase Agreements. (U 39 G)	Application 97-12-005 (Filed December 4, 1997)

OPINION REGARDING PACIFIC GAS AND ELECTRIC COMPANY'S PROPOSED USE OF NATURAL GAS-BASED FINANCIAL INSTRUMENTS TO MANAGE IMPACT OF NATURAL GAS PRICES ON THE COST OF ELECTRICITY UNDER EXISTING POWER PURCHASE AGREEMENTS

Summary

In this decision, we grant conditional authority to Pacific Gas and Electric Company (PG&E) to use natural gas-based financial instruments to manage the impact of natural gas prices on the cost of electricity purchased pursuant to existing power purchase contracts. We make this determination pursuant to our broad powers to regulate utilities which are set forth in the Public Utilities (PU) Code, including, but not limited to, §§ 330(e), 330(l), 451, 454, 491, 701, 701.5, 728, 729, and 816 through 830.[1] The authority to enter into derivatives granted today will end on the earlier of (1) the termination of the rate freeze period, as

[1] All statutory references are to the PU Code, unless otherwise noted.

determined by this Commission; or (2) December 31, 1999. PG&E may file a new application to seek additional authority to extend the limits in the years 2000 and 2001. PG&E is granted an exemption from the Commission's Competitive Bidding Rules[2] set forth in Resolution F-616 for use of the derivatives authorized in this decision.

Background

In Application (A.) 97-12-005, PG&E requests authority to use natural gas-based financial instruments to manage the impact of natural gas prices on the cost of electricity purchased pursuant to existing power purchase contracts, principally Short-Run Avoided Cost (SRAC) energy payments to Qualifying Facility (QF) projects. With this authority, PG&E asserts that it would be able to reduce existing or anticipated price risk associated with its existing power purchase contract costs due to volatile gas commodity costs and related transportation costs. PG&E explains that all risks and benefits will accrue to shareholders and ratepayers will not be impacted at all by this request.

PG&E purchases approximately $400 million per year of power which it states is directly influenced by natural gas prices. PG&E explains that most of these payments are SRAC and Energy Payment Option 3 (EPO3)[3] energy

[2] The Commission's Competitive Bidding Rules require utilities to request bids for the purchase of bonds, notes, and other evidences of indebtedness and are set forth in D.38614, D.49941, D.75556, D.81908, Resolution F-591 (August 4, 1981), and Resolution F--616 (October 1, 1986).

[3] EPO3 gave QFs the option to choose a fixed heat rate (plus or minus an incremental bandwidth) to be used in computing their variable energy payments. EPO3 payments are initially based on SRAC prices. Adjustments are made at year-end to account for differences in the fuel rates and gas prices between each of the EPO3 contracts and the SRAC formula price, resulting in either an additional payment or a deduction from

Footnote continued on next page

payments to QFs. PG&E maintains that gas prices used to calculate the variable-priced payments to QF can be subject to large market price swings, which it seeks to mitigate through the use of these financial hedging instruments. PG&E proposes limits for these financial instruments with a market value not to exceed $400 million for instruments expiring in 1998, $200 million for instruments expiring in 1999, and $100 million for instruments expiring in 2000 and 2001.

PG&E filed A.97-12-005 on December 4, 1997 and it was noticed on the Commission's Daily Calendar of December 9. No party filed a protest to this application. As of January 1, 1998, a prehearing conference had not been held, nor a determination made to hold a hearing. Because no protests were received, Commissioner Conlon and Administrative Law Judge (ALJ) Minkin determined that no hearings were necessary in this proceeding. Accordingly, consistent with Rule 4(c) of the Commission's Rules of Practice and Procedure, the rules and procedures implementing Senate Bill 960 do not apply and the otherwise applicable Commission rules and procedures apply to this proceeding.

Decision (D.) 97-08-058 denied PG&E the authority it requested in A.96-11-037 to use energy-related derivative financial instruments (derivatives), including but not limited to futures contracts, forward contracts, options and swaps to manage gas and electric price risk volatility:

> "If PG&E desires to have this Commission reconsider its request to use energy-related derivative financial instruments, it shall file an application and serve it on parties in Rulemaking 94-04-031 and Investigation 94-04-032. The application shall fully address the interrelationships between the authority it seeks and the issues set forth in this decision, including but not limited to market power

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subsequent payments to the QF. Both EPO3 and SRAC prices are gas-based prices that fluctuate with changes in natural gas prices.

concerns; effects on the mandatory buy-sell requirement; incentives and opportunities to manipulate Power Exchange prices; anticompetitive derivative transactions involving PG&E's generation facilities or generation affiliates (through third-party intermediaries) or PG&E customers; impacts on transition costs; impacts on the rate reduction bonds; and the inability of ratepayers to share in gains from these transactions." (D.97-08-058, Ordering Paragraph 2, mimeo. at p. 15.)

PG&E's Application

PG&E filed A.97-12-005 in response to the concerns identified in D.97-08-058. PG&E is seeking Commission approval to trade financial instruments including 1) exchange-traded futures and options and 2) over-the-counter (OTC) instruments, such as swaps and non-exchange options. PG&E's request includes all financial instruments whose value changes relative to a change in the underlying commodity or commodity transportation cost, and is limited to financial instruments related to gas. PG&E explains that the purpose of entering into such trades is to reduce existing or anticipated price risk associated with managing energy payments to QFs.

The authority sought would end on the earlier of either the termination of the rate freeze period, as determined by this Commission, if it is prior to March 31, 2002 or the end of the transition period specified in § 368(a), that is, no later than March 31, 2002. PG&E affirms that it will not acquire any gas-based financial instruments whose expiration date is after March 31, 2002.

Cost control is particularly important to PG&E because of the rate freeze. Rates are frozen at the June 10, 1996 levels and PG&E's fuel costs are no longer subject to balancing account treatment in the Energy Cost Adjustment Clause, which was eliminated as of January 1, 1998 by D.97-10-057. PG&E wishes to offset the price risk volatility associated with gas commodity and related transportation costs through the use of hedging financial instruments. PG&E

proposes that its shareholders bear all trading losses and retain any gains, so that ratepayers are indifferent to the use of these financial instruments. PG&E pledges to ensure that any direct and indirect costs, such as labor and overhead costs, will be funded by shareholders, as well. PG&E requests that none of the costs, gains, or losses from these financial instruments be subject to reasonableness review.

PG&E seeks authority to engage in trades related to futures, options, and swaps. A future is an exchange-traded contract between a buyer and a seller, where upon expiration of trading, the buyer is obligated to take delivery and the seller is obligated to provide delivery of a fixed amount of commodity at a predetermined price at a specified location. An option is a contract which gives the holder (purchaser) the right, but not the obligation, to purchase (in the case of a "call" option) or sell (in the case of a "put" option) a specific amount of commodity at a fixed price, during a specified period or on a specified date in exchange for a one-time premium payment. The option seller collects the premium and must perform if the purchaser exercises the option. A swap is a contract in which parties agree to exchange cash flows at a preset schedule according to a formula. As a result, one party gets the difference in the cash flows. A fixed-for-floating swap is usually the difference between a preset price and an index price to be determined later. A basis swap is the difference between an index and the New York Mercantile Exchange reference price plus or minus a basis, or differential.[4]

PG&E seeks such approval under the general authority of § 701. PG&E takes the position that such instruments are not necessarily "evidences of

[4] A.97-12-005, Appendix A.

indebtedness" and does not concede that § 818 applies. However, assuming that use of these financial instruments falls within the scope of this section, PG&E seeks approval under § 818. Additionally, PG&E contends that the Competitive Bidding Rules, which require utilities to request bids for the purchase of their debt securities, do not necessarily apply to these financial instruments. In any case, PG&E seeks an exemption from these rules to use such instruments to manage price risk. The Rules require that utilities publish a request for bids in a newspaper and give potential bidders at least a day to respond. PG&E must be able to respond much more quickly to changes in the marketplace in order to effectively make use of these financial instruments.

PG&E asserts that it purchases more than $400 million per year of power, or 20,000 gigawatt hours of energy, under existing power purchase contracts, that are directly influenced by natural gas prices. These contracts require PG&E to make capacity and energy payments. Energy payments are largely SRAC payments, which are currently based on a transition formula, as approved in D.96-12-028, which indexes a starting SRAC energy price to an average of current California gas border price indices. PG&E proposes a limit of $400 million for financial instruments expiring in 1998, $200 million for instruments expiring in 1999, and $100 million for instruments expiring in each of the years 2000 and 2001. These limits are the gross market value of all outstanding positions, subject to limited netting. For example, the 1998 limit would mean that the gross market value of the financial instruments for its power purchase contracts could not exceed $400 million in value at the end of any trading day. This limit would be monitored daily and reported to the Commission. These limits are in addition to the limits adopted in D.98-03-068, which imposes limits on financial instruments to manage the risk associated with natural gas purchased for utility electric generation. PG&E explains that the authority sought in this application addresses a different component of PG&E's costs, which is also subject to the risk of natural gas price fluctuations.

PG&E explains that actual payments under existing power purchase contracts will continue and would not be affected by these hedging instruments. In other words, transition costs that may result from such contracts would neither increase nor decrease because of PG&E's proposal. In addition, PG&E maintains that approval of this proposal will not change the incentives currently in place to lower transition costs by restructuring existing QF contracts. PG&E states that its incentives to restructure these contracts will continue because the bulk of the over-market QF costs are capacity payments rather than the gas-indexed energy payments and because PG&E's shareholders are to retain 10% of any savings resulting from the cost-reducing contract restructurings.[5]

In Resolution E-3506, we determined that "we will not allow Edison to recover any increase or perceived increase in its cost of capital due to its hedging activities." (Resolution E-3506, mimeo. at p. 6.) PG&E agrees to this standard, but asks that it be applied based upon increases which are directly or indirectly caused by use of financial trading, rather than a standard based upon perception.

Under the confidentiality provisions of § 583, PG&E proposes to provide quarterly reports which delineate the aggregate contract volume, market value, and average maturity of all outstanding financial instruments. PG&E will report its end-of-day gross receivable (in-the-money), gross payable (out-of-the-money), and at-the-money positions of its open financial positions, showing both contract volume and market value.

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[5] Issues related to QF contract restructuring and associated shareholder incentives are being addressed in the electric restructuring rulemaking (R.94-04-031) and investigation (I.94-04-032).

PG&E maintains that certain conditions imposed on Edison in Resolution E-3506 should not apply in this proceeding. We directed Edison to include language in any risk management contracts to ensure that the other party to the instrument does not have or will not enter into any contracts with any of Edison's customers, affiliates, or generation facilities. Because Edison was granted authority to hedge the impact of natural gas prices on the cost of electricity and PG&E is not seeking such authority, PG&E contends that such requirements are irrelevant. Further, PG&E believes that while Edison is required to ensure that the Energy Division receives copies of each hedging contract, there is no reason this requirement should apply to PG&E because it proposes that shareholders fund 100% of the costs and take all risk of hedging activity.

PG&E maintains that this application does not raise electric restructuring or market power issues, because 1) the proposed financial instruments are gas-only and therefore preclude the possibility of taking delivery of electricity under futures contracts and thus violating the mandatory buy-sell requirement of the Preferred Policy Decision (D.95-12-063, as modified by D.96-01-009), and 2) PG&E lacks market power in the relevant gas markets. PG&E contends that because of the relatively small volumes to be traded and limits on the use of these financial instruments, PG&E would not be able to exert market power in either the exchange or OTC markets.

Response to ALJ Ruling

In response to various questions posed by ALJ ruling, PG&E has made several assertions. PG&E believes that the authority sought in this application will have no anticompetitive impacts involving PG&E's generation facilities or generation affiliates. PG&E is not requesting authority to use electricity-based financial instruments, nor is it requesting authority to hedge electricity purchases or prices. PG&E states that it is requesting authority to use the same tools to manage costs that are already available to other regulated and unregulated market participants, and that it lacks market power in the physical commodity markets, the national market for exchange-traded futures and options, and the OTC financial market. In compliance with the affiliate guidelines promulgated in D.97-12-088, PG&E will not share hedging and financial derivatives and arbitrage services with affiliates or transmit to affiliates any information which would conflict with the affiliate rules.

In response to questions about the proposed limits and interaction with the provisions of § 390, PG&E explains that its proposed limits are based on the projected amounts of SRAC and EPO3 payments for 1998, which are expected to equal approximately $340 million and $80 million, respectively. PG&E then reduced the 1998 proposed limit in half in recognition of the potential reduction in gas-based SRAC and EPO3 payments due to § 390 and potential QF contract restructurings to derive the proposed limit for 1999 and further reduced this limit to derive the proposed limits for 2000 and 2001.

Section 390(c) provides that SRAC energy payments to QFs shall be based on the market-clearing price of the Power Exchange once certain criteria are met:

> The short-run avoided cost energy payments paid to nonutility power generators by electrical corporations shall be based on the clearing price paid by the independent Power Exchange if (1) the commission has issued an order determining that the independent Power Exchange is functioning properly for the purposes of determining the short-run avoided cost energy payments to be made to nonutility power generators, and either (2) the fossil-fired generation units owned, directly, or indirectly, by the public utility electrical corporation are authorized to charge market-based rates and the "going forward" costs of those units are being recovered solely through the clearing prices paid by the independent Power Exchange for from contracts with the Independent System Operator,

> whether those contracts are market-based or based on operating costs for particular utility-owned power plant units and at particular times when reactive power/voltage support is not yet procurable at market-based rates at locations where it is needed, and are not being recovered directly or indirectly through any other source, or (3) the public utility electrical corporation has divested 90 percent of its gas-fired generation facilities that were operated to meet load in 1994 and 1995. However, nonutility power generators subject to this section may, upon appropriate notice to the public utility electrical corporation, exercise a one-time option to elect to thereafter receive energy payments based upon the clearing price from the independent Power Exchange.

PG&E proposes that it be allowed to continue using gas-based financial instruments to manage the cost of pre-existing contracts even after SRAC payments are based on the Power Exchange price. PG&E asserts that SRAC payments will continue to be influenced by natural gas prices because the Power Exchange price itself is influenced by natural gas prices. PG&E also believes that it would be inefficient to be forced to unwind hedges at an undetermined point, if that point is triggered by uncertain regulatory events. This could lead to additional transaction costs associated with removing or replacing hedges and could be costly if PG&E is forced to unwind hedges during adverse price movements.

PG&E further contends these instruments will have no influence on the Power Exchange price because of the small amount of financial instruments which PG&E would use under the requested authority relative to the volumes traded in the national market and the OTC financial market. Because PG&E believes that use of these instruments will not affect the cost of fuel to, or the willingness of, QFs to produce energy under existing power purchase agreements that will be part of the supply available to the Power Exchange, PG&E predicts that engaging in the trade of such instruments should not influence the Power Exchange price. If this Commission determines that limitations are appropriate, PG&E requests that the gross market value of financial instruments entered into as of that date be capped to establish new limitations for these financial instruments, rather than being forced to unwind the underlying contracts associated with these financial instruments. For example, if the Commission determined that SRAC would be based on the Power Exchange price as of May 1, 1999, and if on that date, the market value of PG&E's positions expiring in 2000 and 2001 is $70 million and $50 million, respectively, those amounts would establish the new limits for instruments expiring in the years 2000 and 2001, rather than the proposed $100 million for each year.

PG&E proposes that shareholders will bear all costs and losses as well as receive all gains from the instruments it will use to manage purchased power gas price risk. All PG&E expenses associated with this program will be included in Federal Energy Regulatory Commission (FERC) account 426.5 (Other Deductions), which is used for other miscellaneous non-operating expenses. Because this account is neither a balancing account nor is included in rate requests there is no impact on the ratepayer. PG&E will also establish an account to track all gains and losses associated with the use of gas financial instruments which will ensure that ratepayers are indifferent.

PG&E does not anticipate that its cost of capital will be impacted by the use of these financial instruments, particularly because of the proposed declining limits associated with the requested authority. PG&E clarifies that standard estimation methods and models routinely used in the cost of capital proceedings can be used to assess changes to PG&E's cost of capital, and by implication, that the impacts of the use of these financial instruments can be separated out.

PG&E explains that it is reasonable that the utility, as the organization responsible for operating the system and managing the costs associated with purchasing natural gas for use in PG&E's generating units, should also be accountable and responsible for the use of financial instruments associated with those fuel costs. It therefore contends that it is reasonable that the utility, rather than the parent holding company, manage these financial instruments and any associated risk.

Discussion

With certain modifications, we are satisfied that PG&E's application and ensuing clarifications ameliorate the concerns we raised in D.97-08-058, particularly because these financial instruments will be gas-based only and will not hedge electricity. In D.97-08-058, we expressed concerns regarding the potential for market power abuses and the impact of such transactions on the mandatory buy-sell requirement of the Power Exchange. Because PG&E is limiting its hedging instruments to a gas-only program, such market power concerns are somewhat allayed. PG&E contends that it lacks market power in both the physical commodity markets, the national market for exchange-traded futures and options, and the OTC financial market. These facts have not been disputed in this proceeding.

FERC has jurisdiction over market power issues and has established a monitoring and mitigation program in its October 30, 1997 Order (*Pacific Gas and Electric Co.*, 81 FERC ¶ 61,122 (1997)). This monitoring and mitigation program includes a review of the behavior of various market participants in each of the Independent System Operator and Power Exchange markets. Reports will be submitted to the FERC and to this Commission. PG&E maintains that this monitoring and mitigation system and the reports it generates will enable this Commission to remain apprised of any issues impacting competition, bidding, or market power concerns. PG&E believes that we would have the right to ask the Independent System Operator and Power Exchange to follow up on any concerns and that we would have the authority to investigate these concerns as part of our ongoing jurisdiction over PG&E's use of financial instruments. We will direct PG&E to include copies of relevant sections of the FERC reports as part of its quarterly reporting requirements.

Consistent with the requirements of D.97-12-088, PG&E is precluded from entering into contracts with its affiliates for such financial instruments and from sharing any information with its affiliates which would conflict with the standards of conduct governing relationships between utilities and their affiliates. Rule V.E. provides, in relevant part:

> "As a general principle, such joint utilization shall not allow or provide a means for the transfer of confidential information from the utility to the affiliate, create the opportunity for preferential treatment or unfair competitive advantage, lead to customer confusion, or create significant opportunities for cross-subsidization of affiliates.
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> "Examples of services that may not be shared include: employee recruiting, engineering, hedging and financial derivatives and arbitrage services, gas and electric purchasing for resale, purchasing of gas transportation and storage capacity, purchasing of electric transmission, system operations, and marketing." (D.97-12-088, mimeo. Appendix A, p. 11.)

PG&E is required to conform to the rules governing affiliate transactions. We find that no particular language need be added to specific contracts to address these prohibitions.

We will modify PG&E's proposed annual limits for this program. We agree that it is undesirable to force PG&E to unwind such hedging contracts based on this finding, and instead will reduce the proposed annual limits.

Section 390 ties SRAC to the Power Exchange market-clearing price when this Commission has determined that the Power Exchange is operating properly for this purpose, and either the utility-owned fossil-fired plants are authorized to charge market-based rates, or 90% of the utility's gas-fired generation is divested. Because of the link to divestiture, we find that a $200 million limit is more reasonable for 1998, given that the sales of the Morro Bay, Moss Landing, and Oakland facilities have been approved in D.97-12-107.[6] PG&E has recently filed A.98-01-008 requesting approval to divest the Hunters Point, Potrero, Pittsburg, and Contra Costa gas-fired power plants, and the Geysers geothermal power plant. As the divestiture proceedings continue, this limit should continue to decline, assuming such sales are approved; therefore, the limit for transactions expiring in 1999, 2000 and 2001 is $100 million for each year. Although we also expect that divestiture transactions will be complete by the end of 1999, we will also authorize PG&E to enter into transactions which expire in 2000 and 2001 because there will still be some risk associated with QF costs that are related to PX prices in a rate freeze environment. Although we recognize the rate freeze may end earlier than the end of 2001, we also recognize that derivatives often have expiration dates 24 to 36 months after the transaction dates. Therefore, it is possible that some derivatives will expire after the end of the rate freeze. To limit this possibility, we decline to extend the expiration dates to March 31, 2002 as requested by PG&E. Further, if the rate freeze ends before December 31, 2001, PG&E shall net out any outstanding contracts through equal and opposite contracts, thereby offsetting the outstanding contract, within a reasonable amount of time.

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[6] D.97-12-107 approves PG&E's application for authority, pursuant to § 851, to sell the Morro Bay, Moss Landing, and Oakland fossil-fuel electric generation plants to affiliates of Duke Energy Power Services, Inc.

If the Commission determines that the Power Exchange is fully functioning for the purposes of setting SRAC equivalent to the market-clearing price prior to divestiture of 90% of PG&E's gas-fired facilities, we will cap the daily limit at the gross market value of PG&E's positions at that point in time, assuming it is less than the limits established for 1998 and 1999. The authority granted today to enter into derivatives will end on the earlier of (1) the termination of the rate freeze period, as determined by this Commission; or (2) December 31, 1999. No derivatives may have expiration dates later than December 31, 2001.

PG&E may file an application to request increases to the limits established herein, in the event that PG&E finds that circumstances indicate that shareholders risks for QF costs have increased. Any such application should not increase the level of risk, direct or indirect, borne by ratepayers.

PG&E requests approval to use its proposed financial instruments under § 701 and any other applicable PU Code sections. We base our review of PG&E's request on our broad powers to regulate utilities, which is set forth in the PU Code. (See, e.g., §§ 330(e), 330(l), 451, 454, 491, 701, 701.5, 723, and 729.) We also review this application in light of the mandates of Assembly Bill (AB) 1890 (Stats. 1996, Ch. 854), which are now incorporated into the PU Code, to ensure a competitive marketplace and on our legal duty to look at all elements of public interest, including competitive issues (*see Northern California Power Agency* v. *Public Util. Com.* (1971) 5 Cal.3d 370, 380).

We adopt PG&E's proposed reporting requirements, with modifications. PG&E should file quarterly reports which provides information on its quarterly maximum end-of-day gross receivable (in-the-money), and gross payable (out-of-the-money), and at-the-money volumes on open financial positions, showing both contract value and market value for the natural gas instruments. To qualify for netting, the instruments must meet three requirements: 1) the financial product must match, 2) the location must match, and 3) time must match (i.e., the product must be bought and sold within the same month). Additionally, the average maturity should be presented as the end-of-day average maturity for both receivables and payables. As stated above, PG&E should include copies of relevant sections of FERC reports. PG&E should identify with specificity exactly what items in each of its quarterly report it requests to be filed under § 583.

To ensure that ratepayers are absolutely indifferent to these transactions, we direct PG&E to establish an account to separately identify all such costs and losses associated with the use of these financial instruments and to exclude these costs and losses from future rate cases or rate increase requests. Reasonableness reviews of these transactions are not required because such activities will be shareholder-funded. PG&E is precluded from including any costs of the financial instruments (direct or indirect) or losses as transition costs or as costs of implementation of direct access, the Power Exchange, or the Independent System Operator under § 376.

PG&E retains the burden of proof to demonstrate that any impacts on its cost of capital, related to trading in these financial instruments, are excluded from future cost of capital proceedings. In Resolution E-3506 (in Edison's Advice Letter 1247-E), we recognized the risks inherent in using hedging instruments, but declined to adopt particular protective measures, as have been adopted in the past for similar hedging instruments used to manage interest rate fluctuations. These protective measures have included requirements that utilities deal only with institutions with a credit rating equal to or better than the utility and requests for the utility to deliver copies of all agreements, along with reports analyzing all costs associated with the agreements in comparison to a projection of all costs without the agreements.

We noted that instead of imposing such restrictions, which serve to mitigate concerns regarding the impacts of such hedging activities on a utility's cost of capital, we would instead not allow Edison to recovery any "increase or perceived increase in its cost of capital due to its hedging activities." (Resolution E-3506, mimeo. at 6.) We make a similar finding in this proceeding. We will not adopt any particular protective measures at this time, but will ensure that PG&E demonstrates through an affirmative showing that such hedging has not increased its cost of capital. We will adopt the requirement of Resolution E-3506 that copies of each hedging contract be provided to the Energy Division for monitoring purposes.

In general, we prefer that PG&E's use of gas-based derivatives should be limited to those traded at an established exchange regulated by the Commodity Futures Trading Commission. We previously determined that we would not limit Edison to such a restriction, but recognized that these restrictions could alleviate market power concerns and help to mitigate the substantial increase in risk associated with the use of hedging instruments. (Resolution E-3506, mimeo. at 7.) Because shareholder are shouldering the risk of these activities, we will allow PG&E to engage in OTC transactions as well, but expect that PG&E will include enough information in its quarterly reports to allow us to assess whether such transactions should continue.

As stated in D.97-08-058, we believe that many derivatives are an evidence of indebtedness. Derivatives are contracts that involve the payment of money or the performance of some other act in the future. However, we agree with PG&E's concerns that to manage its risk effectively, it must be able to respond quickly to changes in the market, often within minutes. Publicly requesting bids would put PG&E at a disadvantage relative to other market participants. It is reasonable, therefore, to exempt PG&E's use of gas-based derivatives traded either at an established exchange or OTC, from the Competitive Bidding Rules.[7]

Findings of Fact

1. The purpose of PG&E's request is to manage the impact of natural gas price risk on the cost of electricity purchased pursuant to existing power purchase contracts during the rate freeze mandated by § 368.

2. PG&E is requesting authority to use the type of financial instruments to manage gas costs that are already available to other regulated and unregulated market participants.

3. Shareholders should bear all costs and losses as well as receive all gains from the instruments PG&E will use to manage gas price risk.

4. PG&E asserts that it lacks market power in the physical commodity markets, the national market for exchange-traded futures and options, and the OTC financial market.

5. Once SRAC is set equal to the Power Exchange market-clearing price, these hedging transactions may have the potential to influence the market-clearing price in an anticompetitive fashion.

6. Because of the link to divestiture, it is reasonable to adjust PG&E's proposed limit for trading in these gas-based financial instruments to a daily limit of $200 million for 1998 and to $100 million each year for 1999, 2000 and 2001.

7. There is a need to authorize transactions at this time which expire in 2000 and 2001 even though we expect that the SRAC price will be set at the Power

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[7] "Debt issues for which competitive bidding is not viable or available are exempt." (Resolution F-616, mimeo. at 2.)

Exchange market-clearing price and divestiture transactions will be completed by year-end 1999, because there remain risks associated with QF costs during the rate freeze period. Because of the potential early end of the rate freeze, there is a need to limit expiration dates for transactions to December 31, 2001.

8. If the Commission determines the end of the rate freeze to be before December 31, 2001, there is a need to ensure that outstanding contracts are netted out in a reasonable amount of time.

9. Separately identifying and tracking all costs, whether direct or indirect, and all losses associated with the use of the derivatives authorized by this decision will allow PG&E to exclude these costs and losses from future rate increase requests.

10. PG&E's costs of using natural gas-based financial instruments to manage gas costs associated with power purchase contracts, whether direct or indirect, and any losses resulting from such instruments are prohibited from being categorized as transition costs and PG&E may not claim that such costs fit the description of implementation costs of electric restructuring, as described in § 376.

11. The risks associated with trading in gas-based financial derivatives shall not be used to justify PG&E's request for increases in its cost of capital. PG&E has the burden of proof that such risks have no impact on future requests.

Conclusions of Law

1. Until SRAC energy payments are tied to the Power Exchange market-clearing price and their rate freeze is ended, PG&E's request to trade in natural gas-based financial derivatives does not impact the mandatory buy-sell requirement for electricity purchases and sales of the Preferred Policy Decision.

2. In compliance with the affiliate guidelines promulgated in D.97-12-088, PG&E is precluded from entering into contracts for hedging and financial

derivatives with its affiliates and from sharing hedging and financial derivatives and arbitrage services with affiliates or transmitting to affiliates any information which would conflict with the affiliate rules.

3. It is reasonable that shareholders assume all risks and rewards for these speculative investments.

4. Section 390 links SRAC to the Power Exchange market-clearing price when certain criteria is met, including 90% divestiture of the utility's gas-fired generation.

5. It is reasonable to establish daily gross market value limits for 1998 and 1999 based on the assumption that divestiture of 90% of PG&E's gas-fired generation facilities will be completed by December 31, 1999, and that the SRAC price will be set at the Power Exchange market-clearing price by year-end 1999, and to continue the 1999 limits until the earlier of the end of 2001 or the end of the rate freeze.

6. If the Commission determines that the Power Exchange is fully functioning for the purposes of setting SRAC equivalent to the market-clearing price prior to divestiture of 90% of PG&E's gas-fired facilities, the daily limit should be capped at the gross market value of PG&E's positions at that time, assuming it is less than the limits established for 1998 and 1999.

7. Derivatives that are the subject of this decision should not have an expiration date later than December 31, 2001 because of the potential early end of the rate freeze. Any outstanding contracts at the date of the end of the rate freeze should be netted out through equal and opposite contracts which would offset the outstanding contract.

8. Gas-based financial derivatives are a form of indebtedness and subject to the requirements of § 818.

9. Subjecting PG&E's use of gas-based financial derivatives to the Competitive Bidding Rules would put PG&E at a disadvantage relative to other market participants.

10. It is reasonable to exempt PG&E's use of gas-based financial derivatives for managing the price risk of gas associated with its power purchase contracts from the Competitive Bidding Rules.

11. We base our review of PG&E's application on § 701 and on the broad powers of the Commission to regulate utilities, including but not limited to §§ 330(e), 330(l), 451, 454, 491, 701, 701.5, 728, 729, and 816 through 830.

12. The authority granted in this decision to enter into derivatives should expire at the end of the rate freeze or on December 31, 1999, whichever is earlier, except for those transactions required to comply with Conclusion of Law 7.

13. It is reasonable to require PG&E to adhere to the reporting requirements discussed in this decision.

14. It is reasonable to require PG&E to submit copies of all hedging contracts to the Energy Division.

15. This proceeding should be closed.

ORDER

IT IS ORDERED that:

1. Pacific Gas and Electric Company's (PG&E) Application (A.) 97-12-005 is approved with the following conditions and to the following extent:

   a. PG&E's use of gas-based derivatives for the purpose of managing price risk associated with power purchase contracts is limited to a daily market value maximum of $200 million for 1998.

   b. PG&E's use of gas-based derivatives for the purpose of managing price risk associated with power purchase contracts is limited to a daily market value maximum of $100 million for each of 1999, 2000 and 2001.

c. If the Commission determines that the Power Exchange is fully functioning for the purposes of setting short run avoided costs equivalent to the market-clearing price prior to divestiture of 90% of PG&E's gas-fired facilities, the daily limit shall be capped at the gross market value of PG&E's positions at that time, assuming it is less than the limits established in Ordering Paragraphs 1.a. and 1.b.

d. Costs, whether direct or indirect, and losses associated with the use of these derivatives shall be tracked and recorded in a separate account.

e. Costs, whether direct or indirect, and losses associated with the use of these derivatives shall be borne by shareholders and shall not be recoverable in future rate requests or as a request as implementation costs of electric restructuring, as defined in Public Utilities Code Section 376.

f. No derivatives shall have an expiration date later than December 31, 2001.

g. If the Commission determines that the rate freeze ends earlier than December 31, 2001, any outstanding contracts shall be netted out through equal and opposite contracts which offsets the outstanding contract, within a reasonable period of time.

2. On or before January 15, April 15, July 15, and October 15 of each year, beginning July 15, 1998, and ending January 15, 2002, PG&E shall file a report for the previous quarter, providing information on PG&E's quarterly maximum end-of-day gross receivable and gross payable and at-the-money volumes on open financial positions, showing both contract volume and gross market value for the natural gas-based financial instruments. To qualify for netting, instruments must meet three requirements: a) the financial product must match; b) the location must match; and 3) time must match (the product must be both and sold within the same month). These reports shall be provided to the Energy Division.

3. Within ten days of executing each contract, PG&E shall send a copy of each hedging instrument it enters into under this program to the Energy Division.

4. The authority to enter into derivatives granted in this decision shall expire at the end of the rate freeze or on December 31, 1999, whichever comes first, except for those transactions required to comply with Ordering Paragraph 1(a).

5. PG&E may file an Application to extend the limits imposed herein if its risks related to QF costs increase. Any such Application shall not increase direct or indirect ratepayer risks.

6. A.97-12-005 is closed.

This order is effective today.

Dated June 18, 1998, at San Francisco, California.

RICHARD A. BILAS
President
P. GREGORY CONLON
JESSIE J. KNIGHT, JR.
HENRY M. DUQUE
JOSIAH L. NEEPER
Commissioners