

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Address
the Gas Utilities' Incentive Mechanisms
and the Treatment of Hedging Under
Those Incentive Mechanisms.

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**ORDER INSTITUTING RULEMAKING ON THE COMMISSION'S OWN
MOTION TO ADDRESS THE GAS UTILITIES' INCENTIVE MECHANISMS
AND THE TREATMENT OF HEDGING UNDER THOSE INCENTIVE
MECHANISMS**

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1. Summary

This Order Instituting Rulemaking (OIR) will examine the California gas utilities' gas cost incentive mechanisms and the treatment of hedging¹ costs under those incentive mechanisms as ordered by Decision (D.) 07-06-013.² Particularly in view of the significant degree of gas supply and price volatility in recent years, the treatment of hedging costs, and the design of incentive mechanisms are important issues affecting both utility investors and their retail customers. The purpose of this OIR is to determine whether the utilities' natural gas "hedging" plans can and/or should be incorporated into their incentive mechanisms. We also shall address whether, as a general matter, we need to re-examine the design of the utilities' current incentive mechanisms to provide the proper economic signals to manage ratepayer costs prudently while encouraging innovative solutions for improving performance.

In broad terms, this OIR will address the following issues:

- the guidelines and policies each utility currently uses to operate its hedging plan;
- whether, or to what extent, the Commission should establish uniform statewide hedging guidelines and policies for all California gas utilities;

¹ As explained in further detail herein, hedging is a form of price insurance used to protect customers from excessive swings in natural gas prices.

² D.07-06-013, Ordering Paragraph (OP) 3.

- whether, or how, hedging costs should be re-integrated into the existing incentive mechanisms in order to provide appropriate management accountability and responsiveness in view of the inherent risks and rewards associated with hedging;
- alternatively, whether a separate incentive mechanism can be designed to compare the cost of a hedging program with market benchmarks thus creating an incentive to manage costs, while allocating potential gains or losses from the hedging program among investors and customers in a fair and economically efficient manner;
- the process under which the utilities' should request authority for their hedging plan; and
- whether the utilities' current incentive mechanism designs should be revised in order to promote a more appropriate sharing of risks and rewards assuming that hedging costs and savings are excluded entirely from the incentive mechanisms.

In the present rulemaking, the Commission is naming as Respondents the following California utilities: Pacific Gas and Electric Company (PG&E), San Diego Gas & Electric Company (SDG&E), Southern California Gas Company (SoCalGas), and Southwest Gas Corporation (SWG). The Commission invites all other interested parties to file initial comments on the issues and/or reply comment to the initial comments of the California utilities and other parties.

2. Background

On June 7, 2007, the Commission issued D.07-06-013 which ordered that a rulemaking be instituted to undertake a review of the gas utilities' incentive mechanisms and the treatment of hedging under those incentive mechanisms. On December 6, 2007, the Commission issued D.07-12-002, which granted the

Division of Ratepayer Advocates (DRA) petition to defer issuing the OIR to June 2008.³

First authorized by D.93-06-092 for SDG&E, gas cost incentive mechanisms were intended to be an improvement over traditional reasonableness reviews whereby costs were merely passed through to ratepayers with no recognition of superior management success in lowering costs. While certain details differ, all utility incentive mechanisms compare the cost of natural gas purchases to a monthly market gas price benchmark, and allocate a share of the performance that is either better or worse than the benchmark between shareholders and ratepayers. A “dead band” around the benchmark delineates the range of costs to be shared by ratepayers and shareholders.

Unlike the traditional reasonableness review, the incentive mechanisms reward utility management for lowering gas costs to ratepayers, but also reduce utility earnings if costs rise relative to the benchmark. At the same time, the incentive mechanisms eliminate the requirement for hindsight reasonableness reviews of costs, thereby reducing regulatory burdens and complexity for all parties. In this manner, the incentive mechanisms are designed to: (1) promote sound business decisions regarding gas purchases without micromanagement by regulators; (2) encourage innovative methods for improving performance; (3) allow flexibility to adjust to changing circumstances; and (4) preserve accountability for management actions.

³ The Commission granted deferral to avoid scheduling conflicts with SoCalGas’ and SDG&E’s Biennial Cost Allocation Proceedings (BCAPs).

The Commission has repeatedly expressed support for regulatory mechanisms that provide utilities an incentive to manage costs well through exposure to risks as well as opportunities for rewards for sound management decision-making.⁴ The potential for a shareholder reward or penalty has encouraged the utilities to make timely and appropriate decisions in a dynamic market to compete vigorously for the lowest-cost supply and delivery of gas.

In addition to the goal of minimizing the overall level of gas costs, another closely related management goal is to mitigate the *volatility* of gas prices paid by core customers. The Commission recognizes financial hedging as one of the tools to be utilized to protect core customers from extreme price increases. Financial hedging is a form of price insurance used to protect customers from excessively high and volatile natural gas price swings. The hedge involves one or more financial instruments arranged with a counterparty providing a guarantee that the price exposure for the hedged portion of gas supply does not exceed a designated level.⁵

As is true with all insurance, there is a cost involved in obtaining this price protection, and hedges entail their own risk. For example, if the utility hedges against an increase in the price of natural gas by agreeing to buy large quantities at a fixed price, and the market price of gas declines below the fixed price, ratepayers would be worse off with the hedge. Under such a scenario where gas prices decline, the utility's counterparty may demand collateral from the utility

⁴ D.02-06-023, D.02-08-070, D.04-01-047.

⁵ Examples of financial hedging instruments include options to purchase or sell gas at a predetermined price or contracts for a future delivery of a fixed amount of gas at a fixed price.

to mitigate the risk that the utility will not pay the agreed-upon price, and instead purchase lower cost gas from another party. The demand for collateral constitutes a “margin call.” Depending on the counterparty, a margin call could be in the form of cash or letters of credit. The New York Mercantile Exchange (NYMEX) only accepts cash, while others accept cash or letters of credit. The potential for such risks is not merely theoretical. In D.06-11-006, for example, we provided PG&E with the ability to finance large margin calls on gas hedges by expanding PG&E’s general short-term debt authority from \$1.5 billion to \$2.0 billion. Additionally, D.06-08-027 excluded from PG&E’s Core Procurement Incentive Mechanism (CPIM) all of the costs and benefits of hedges resulting from PG&E’s approved gas hedging plan. Thus, PG&E had no risk either for the costs of hedges or for margin calls on gas hedges that result from its approved hedging plan.

Therefore, in this OIR, we shall assess the value of price protections offered by hedging weighed against the associated costs of hedging, including the potential risks of margin calls. Moreover, it is essential to address whether or how potential risks and rewards involved with hedging should be shared between ratepayers and shareholders to provide the appropriate incentives and accountability for management decisions.

Prior to 2005, financial hedges were always a part of each utility’s respective incentive mechanism. Each utility purchased hedging instruments over the years as part of its natural gas portfolio subject to its incentive mechanism. However, as a result of severe disruptions in natural gas supplies and prices in the summer of 2005, the utilities requested a modification in their respective incentive mechanisms.

The primary cause of these disruptions was Hurricane Katrina which struck on August 29, 2005, hitting the heart of the natural gas and oil producing region of the Gulf of Mexico. Hurricane Katrina – and to a lesser extent Hurricane Rita – had a major adverse impact on natural gas markets, contributing to significant increases in the price of natural gas throughout the United States. Gas prices for the following winter rose from \$10 to above \$12.00 per million British thermal unit (MMBtu) (or per decatherm, Dth) on NYMEX, and created the substantial possibility of further multi-dollar per MMBtu increases due to the resulting loss of gas production. The fact that these hurricanes came not long after the 2000-2001 energy crisis when natural gas prices at one point hit \$60 per MMBtu contributed to the many perceived factors to act and protect core customers from gas price volatility.

With the-then upcoming 2005 winter, another hurricane in the Gulf of Mexico affecting gas supply could have had a significant upward effect on prices. Typically, September is the peak month for hurricane activity furthering the cause for concern.

Consequently, on September 13, 2005, PG&E filed a Petition for Modification, on an emergency basis, of D.04-01-047.⁶ That decision, among other things, approved the continuation of PG&E's Core Procurement Incentive Mechanism (CPIM). PG&E argued that emergency action was needed to protect its core gas customers from natural gas price spikes in the coming winter and in subsequent winters because the recent events highlighted the market's volatility and susceptibility to sudden and sustained price spikes due to events such as

⁶ That decision was in Rulemaking (R.) 02-06-041. PG&E served its petition on the parties to that proceeding.

Katrina.⁷ PG&E requested that all costs incurred under its proposed hedging plan on behalf of its core gas customers for that winter be accounted for outside of the CPIM, with 100% of the hedging costs and benefits passed on to core customers.

On October 11, 2005, SoCalGas and SDG&E filed a similar emergency petition to modify D.02-06-023 and D.03-07-037. Similar to PG&E's request, SoCalGas and SDG&E sought to modify their respective Gas Cost Incentive Mechanism (GCIM) and Gas Procurement Performance Based Ratemaking (PBR) Mechanism so that they could undertake an expanded level of hedging of their natural gas purchases on behalf of their respective core gas customers for the coming winter. The emergency petition also requested that all of the costs and benefits of the expanded hedging plans, and the gas hedging that had already taken place for the 2005-2006 winter, be allocated directly to their core gas customers.

The utilities generally argued that the existing incentive mechanisms did not provide adequate protections to motivate management to engage in optimal levels of hedging needed to protect ratepayers. Based on their claim that hedging instruments generally entailed too much shareholder risk under the existing incentive mechanisms, the utilities requested that costs of the proposed hedging plans for that winter be removed from the incentive mechanisms.

On October 6, 2005, the Commission issued D.05-10-015, approving PG&E's confidential hedging plan and removing the expenditures of winter financial hedging from PG&E's CPIM. On October 27, 2005, the Commission issued

⁷ D.05-10-015 at p. 1.

D.05-10-043, likewise approving SoCalGas and SDG&E's confidential hedging plan and removing the expenditures on financial hedging from SoCalGas' GCIM and SDG&E's PBR.

On August 24, 2006, the Commission issued D.06-08-027 approving the confidential hedging plans of PG&E, SoCalGas and SDG&E⁸ for the 2006/2007 winter season. In this decision the Commission limited hedging expenditures for the three utilities to \$14 per core customer on average for the 2006-2007 winter season, or to the utilities' proposed expenditure amounts – whichever was lower. (However, the Commission determined that these limits would not include any costs associated with swaps or futures.) Similar to the prior year's hedging decisions, D.06-08-027 removed the expenditures authorized for financial hedging from the utilities' respective natural gas cost incentive mechanisms. Instead, all of the costs and savings, if any, from hedging were assigned 100% to ratepayers.

In D.06-11-066, the Commission authorized PG&E to issue \$500 million of additional short-term debt, for total short-term debt authority of \$2 billion, for use in financing margin calls on gas purchase contracts and Commission-authorized hedges that could result from declines in the price of natural gas.⁹ This action further increased potential ratepayer risk from hedging.

⁸ These hedging plans will remain confidential as there is highly sensitive market information involved and if released, could work toward the detriment of utilities' ratepayers.

⁹ We expressed concern in D.06-11-066 that PG&E margin calls on gas hedges could reach \$900 million, which could signal an impending large-scale failure of PG&E's hedging activities. PG&E's ratepayers might then have to pay significantly more than the then-current market price of gas. In light of this risk, PG&E was required to provide notice whenever margin calls that are not offset by other hedges reached \$300 million,

Footnote continued on next page

On June 7, 2007 the Commission issued D.07-06-013 approving PG&E's Application 06-05-007 for authority to purchase gas hedges for seven years following a pre-approval of its annual plan by way of an annual expedited advice letter process. Financial hedges would be undertaken on a rolling three-year basis via an Annual Plan filing. There will be five Annual Plan filings beginning with the 2007-2008 winter season that will authorize a hedge plan for the current winter season and the subsequent two winter seasons. Thus, the final Annual Plan (Year five) will be filed for the 2011-2012 winter season and this plan will run through the 2013-2014 winter season. Starting in 2009, if any member of the Advisory Group¹⁰ desires to change or modify the program, it can notify the other members of the Advisory Group by February 1, and PG&E, after discussions with the Advisory Group, must file by June 30 before the Commission an application or other filing vehicle to continue, modify or terminate the program.¹¹

D.07-06-013 authorized PG&E to continue to spend core ratepayer funds on hedging instruments outside of the CPIM. Ratepayers assume all costs of these purchases and receive all of the benefits, if any. The CPIM imposes some risk and provides some rewards to PG&E depending on whether PG&E's gas purchases are more or less expensive than a market-based benchmark.

\$600 million, \$900 million, and each \$300 million increment thereafter for the first time in each calendar quarter (*see* D.08-01-010, OP 2).

¹⁰ Pursuant to D.07-06-013, PG&E established an advisory group comprised of TURN, DRA, & Aglet for purposes of representing the core interest.

¹¹ D.07-06-013 at p. 5.

On December 6, 2007, the Commission issued D.07-12-019 approving among other matters a three-year hedging period for SoCalGas and SDG&E, subject to reevaluation after the third year, which is the 2009-2010 winter hedge period. D.07-12-019 also consolidated the separate gas commodity procurement and management functions of SoCalGas and SDG&E into one gas portfolio to be managed by SoCalGas. It further adopted the proposal that the combined procurement function be subject to SoCalGas' GCIM.

SWG requested Commission approval of a gas cost incentive mechanism in 2004, and the Commission in D.05-05-033 granted SWG's request. In response to the other utilities' requests that prompted D.05-10-015 and D.05-10-043, SWG stated that since it had recently begun operating under its first GCIM cycle, it had already implemented its hedging program for the 2005-2006 period and that it did not recommend suspending its program. As explained in more detail below, SWG's GCIM contains a "Volatility Mitigation Program" (VMP) which involves fixed price contracts entered into for price mitigation. These fixed price contracts are the hedging instrument used by SWG to protect against extreme price increases. SWG does not engage in financial hedging. The VMP purchases are flowed through to its customers, and thus have no impact on GCIM rewards or penalties.

3. Summary of Utility Incentive Mechanisms

It is instructive to summarize each of the utilities' incentive mechanisms and their hedging activities to date as a starting point to better understand what steps the Commission should take in addressing the treatment of hedging in connection with the design of incentive mechanisms going forward. Our purpose is not to engage in a hindsight review, however, but rather to provide a framework for lessons learned as to how incentives for hedging have worked

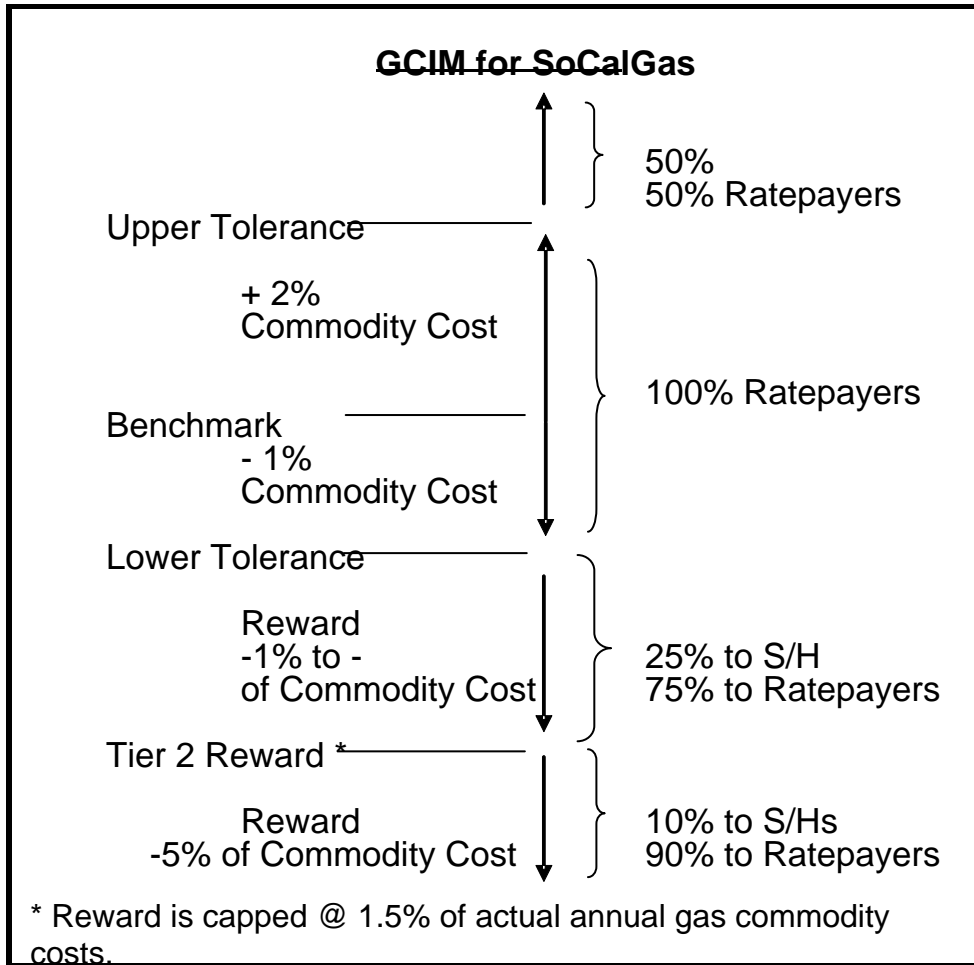
over the past three winters, and how those lessons may be applied in reforms that we implement going forward.

As of April 1, 2008, SoCalGas' Gas Acquisition Department is responsible for supplying core customers of SoCalGas as well as SDG&E, and procurement costs for the combined portfolio of both utilities will be under the SoCalGas GCIM structure. The SoCalGas GCIM program was originally approved in D.94-03-076 with many subsequent modifications and extensions. The GCIM was designed (a) to provide more efficient regulatory controls than its predecessor, *i.e.*, annual reasonableness reviews; (b) to balance the interests of core customers and shareholders, and; (c) to give utilities market-based incentives to acquire gas at the lowest possible cost while taking on some associated risks.

To achieve the GCIM objectives, the Commission allows SoCalGas to use a number of cost-saving gas procurement methods such as the physical sale of gas to third parties and hub transaction activities.¹² The GCIM provides for the measurement of gas purchasing performance by weighing actual performance against a "...benchmark cost of gas intended to emulate actual market conditions on a monthly basis." The GCIM provides for a tolerance band, or deadband, around the benchmark cost.

¹² Up until GCIM Year 11 (calendar year 2005), financial derivatives were completely included within the GCIM to reduce and effectively manage the cost of gas for its core ratepayers. In GCIM Year 12 and 13, SoCalGas performed its winter hedging outside of its GCIM, as authorized in D.05-10-043 and D.06-08-027, respectively.

SoCalGas' GCIM can be depicted as follows:

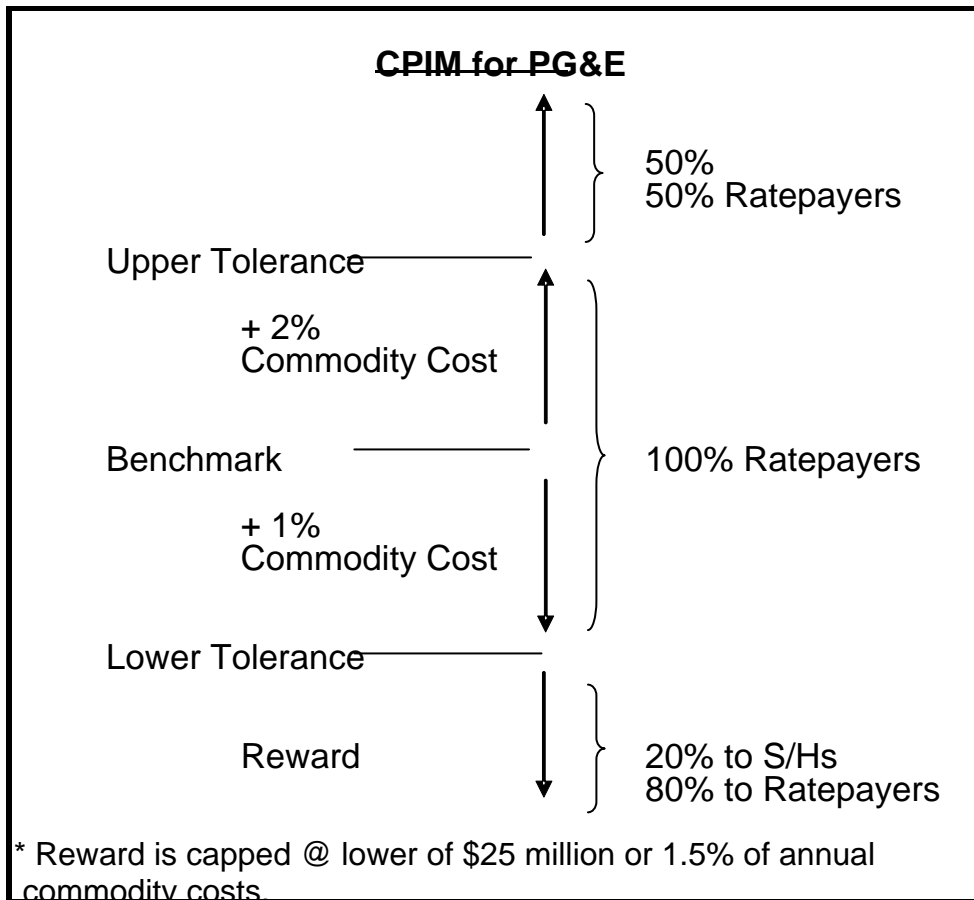


PG&E's Core Procurement Department manages its gas procurement costs under the CPIM, as approved in D.97-08-055,¹³ which established the methodology to recover core gas procurement costs. The CPIM provides a market-based measure of the performance of PG&E's Core Procurement Department, as a means for the Commission to ensure the reasonableness of costs incurred on behalf of core customers. The allowed monthly benchmark

¹³ The CPIM was based on the PG&E/ORA Post-1997 CPIM Agreement and PG&E's Supplemental Report Describing the Post-1997 CPIM.

dollars over the annual CPIM period are compared to actual costs to determine PG&E's performance. A tolerance band is constructed around the benchmark, and is defined as a range of costs that is considered reasonable. If PG&E's actual gas costs, as measured against the CPIM benchmark are between the upper and lower limit specifications for the tolerance band, there is no shareholder reward or penalty for the CPIM period. If actual costs or savings fall outside the tolerance band, there will be sharing between ratepayers and PG&E shareholders of associated gains or losses that exceed the tolerance band.

PG&E's CPIM can be depicted as follows:

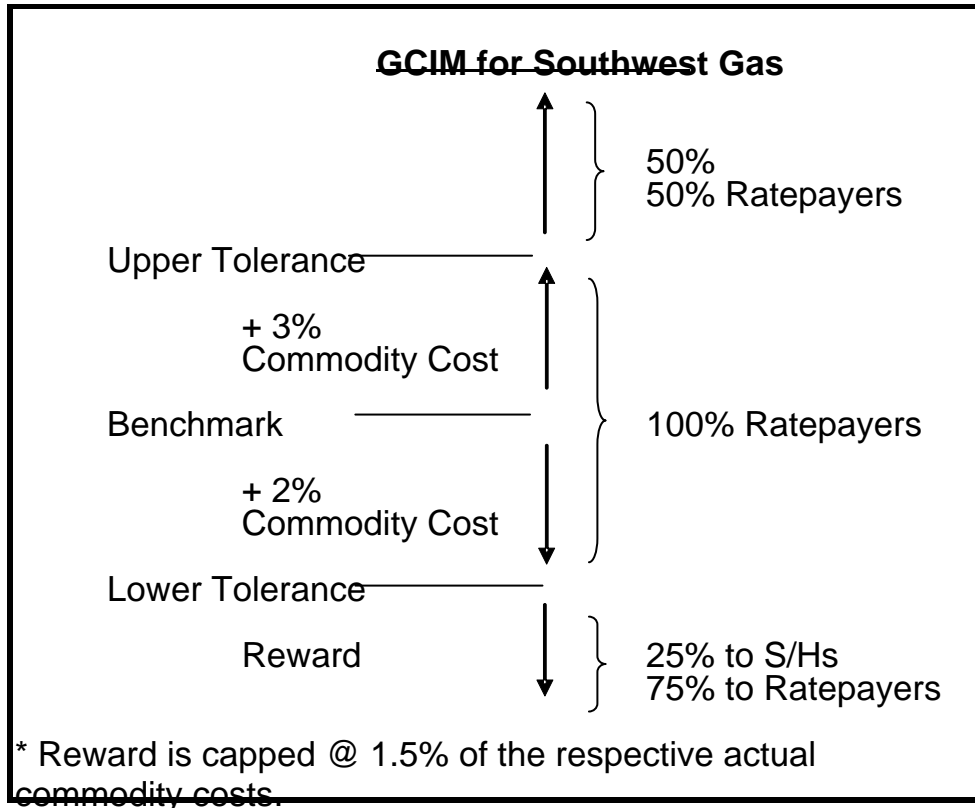


Pursuant to D.05-05-033, SWG first established its gas cost incentive mechanism. SWG's GCIM provides an objective standard by which to measure SWG's gas procurement performance, an incentive to lower overall gas costs, and a sharing of gas procurement benefits between ratepayers and SWG. Any actual savings or costs that exceed either the upper or lower tolerance bands are shared between shareholders and ratepayers, calculated as a percentage of the annual gas cost benchmark. The SWG GCIM also includes a storage capacity target¹⁴ and a "Volatility Mitigation Program" (VMP) which involves fixed price contracts entered into for price mitigation. The VMP purchases are flowed through, and thus have no impact on GCIM rewards or penalties.¹⁵ Transportation and storage costs are also flowed through and do not impact the GCIM.

¹⁴ The GCIM requires Southwest to have storage reserves filled to a target level of 80% of capacity by November 1, of each year. Failure to meet the 80% target requires Southwest to explain the variance to core customers in the annual GCIM filing.

¹⁵ VMP purchases are limited to 25% of the forecasted annual gas supply.

Southwest Gas' GCIM can be depicted as follows:



4. Summary of Winter Hedge Plans

The utilities have completed three years of hedging subject to cost recovery outside the incentive mechanisms beginning with winter 2005-2006. The winter hedge plans are all submitted on a confidential basis to the Commission. DRA files an annual report on each incentive mechanism and, as part of this report, also indicates the total expenditure for the winter hedge plan. Since DRA has not filed its annual reports for winter 2007-2008, we cannot at this time divulge the expenditure. However, for the first two hedging years, DRA has published their reports showing the amounts spent to protect core customers from extreme price increases: In total, these three utilities have spent over \$200 million to hedge for the first two winters of their expanded hedging programs, allocated as follows:

- PG&E has spent over \$134 million
- SoCalGas has spent just over \$46 million
- SDG&E has spent over \$29 million

As approved in D.05-10-015 and D.05-10-043, the first winter hedge plans (winter 2005-2006) for the utilities were comprised of confidential hedging plans subject to expenditure limits. The decisions authorized an increase for average residential customer's monthly bill by approximately \$2.00. In D.05-10-015, PG&E was also given authorization to hedge for the upcoming two winters and to file an application addressing long-term financial hedging. SoCalGas' hedging plan was approved as requested, which was on an annual basis. In similar fashion, for the 2006-2007 winter period, the Commission approved hedging plans for each utility.

PG&E's plan as approved in D.07-06-013 was undertaken on a rolling three-year basis via an Annual Plan filing beginning with the 2007-2008 winter season. After the initial three-year term, the Program will continue on an annual basis, unless a member of the Core Hedging Advisory Group¹⁶ notifies the other members of its desire to modify the Program. The Program provides for an annual budget for options as well as a separate authority to hedge with swaps for a certain specified level. The per-customer impact of the plan should be about \$14 for the winter months.

¹⁶ The hedge plan also includes a "Core Hedging Advisory Group" comprised of PG&E, DRA, Aglet and TURN. The advisory group would meet quarterly to confer about the Annual plans and related hedging operations.

SoCalGas' winter hedge plan as approved in D.07-12-019 is undertaken via an annual hedge plan application for an initial three-year period, subject to reevaluation after the third year, which is the 2009-2010 winter hedge period. As with PG&E's decision which has a customer impact of about \$14, D.07-12-019 does not specify a specific dollar amount, but rather an annual hedge plan that must be filed via an application. As noted above, D.07-12-019 combined the core portfolios of SoCalGas and SDG&E. Therefore, SDG&E's core is now combined with that of SoCalGas and it is SoCalGas' Gas Acquisition Department who has the responsibility for the core portfolio of itself as well as that of SDG&E.

5. Preliminary Scoping Memo

In this Preliminary Scoping Memo, we describe in broad terms the issues to be considered in this proceeding regarding prospective changes to the gas utilities' incentive mechanisms and the treatment of hedging under those incentive mechanisms.

This Rulemaking will examine:

- the guidelines and policies each utility uses to operate its hedging plan;
- whether the Commission should establish statewide hedging guidelines and policies for all California gas utilities;
- whether hedging costs should be re-integrated into the existing incentive mechanisms, and if so, how;
- alternatively, if a separate incentive mechanism can be designed to compare the cost of a hedging program with market benchmarks thus creating an incentive to manage costs, but that would not penalize a utility for the profit or loss of the hedging program;

- the process under which the utilities' will request authority for implementation of their hedging plan;
- Whether the removal of hedging cost recovery from the incentive mechanisms results in reduced risk borne by shareholders. If so, whether (and how) the incentive mechanisms should be revised to maintain an appropriate sharing of risks/rewards between shareholders and ratepayers; and
- What timetable should apply for purposes of transitioning from currently adopted rules and processes to any revised arrangements adopted through this proceeding.

Depending on the timetable adopted in this OIR for implementing any modifications to existing rules and processes, modifications to the utilities' currently adopted long-term hedging plans may be required. Accordingly, we hereby place parties on notice that the treatment of long-term hedging plans adopted for PG&E and SoCalGas in D.07-06-013 and D.07-12-019, respectively, may be subject to modification as a result of reforms adopted through this rulemaking

In reviewing the existing incentive designs and hedging practices among the utilities, we recognize that differences between utilities may be attributable to operational variations. We also, however, remain mindful of the benefits of applying conceptual consistency in formulating future regulatory standards and policies applicable to the respondent utilities. While there may be reasons for different designs in incentive mechanisms and treatment of hedging costs, we intend to consider whether, or in what manner, incentive guidelines and hedging policies should apply across the board to all utilities in order to ensure appropriate risk mitigation at reasonable cost.

Currently, it seems that each utility operates under different policies with varying effects on ratepayers. For example, SWG does not engage in financial hedges at all, but does have a Volatility Mitigation Program which includes fixed price contracts entered into for price mitigation. PG&E and SoCalGas, our two largest gas utilities, both utilize hedging, but each seem to be operating under different guidelines or strategies. PG&E has spent almost three times more than SoCalGas, yet PG&E has fewer core customers to protect.¹⁷ We recognize that one possible explanation for at least some of PG&E's relatively higher level of expenditures may be that PG&E's core customers consume more gas in the winter due to a colder climate relative to that of Southern California.

In this proceeding, we seek to gain a better understanding of the reasons for differences in how incentives and hedging policies are applied among the utilities, while protecting the confidentiality of the utilities' hedging plans. As stated in past decisions, the hedging plan is to remain confidential as there is presumably highly sensitive market information involved which, if released, could work toward the detriment of ratepayers. It should, however, be noted that many hedging instruments can be purchased in a liquid and transparent market, and DRA publishes an after-the-fact review of the utilities' performance.

¹⁷ According to PG&E's website there are 4.2 million customers while SoCalGas has 5.1 million customers.

We must first decide at a policy level what the appropriate level of wholesale natural gas price volatility is for core customers. If PG&E is spending three times more for price hedging than does SoCalGas, which has more core customers to protect, then it seems that one utility defines the appropriate level of gas price volatility differently from the other. Alternatively, one utility may have a larger physical hedge (*e.g.*, with storage), thereby allowing them to use a reduced amount of financial hedges. The huge discrepancy begs the question of whether and how the utilities are actively managing their hedging programs. The Commission needs to understand the impact on ratepayers of the different utility hedging plans and vehicles to allocate risks between shareholders and ratepayers. It is also instructive to understand how and the degree to which financial hedging is being utilized to protect against rate volatility and/or extreme price increases. Bill volatility can be stabilized via level pay plan programs currently in place for each utility. This rulemaking should address whether it makes sense to establish a consistent policy across the board that determines when winter hedging should begin, what the acceptable level of gas price volatility is, and what level of risk should be undertaken in order to ensure reasonable expenditures of ratepayer dollars.

We shall also consider how incentives should be provided for effectively managing the hedging programs. The profit/loss of a hedging program is mainly determined by market fluctuations, and only marginally impacted by utility performance. The utilities have argued that they should not be at risk for the profit/loss of a hedging program. As stated previously, beginning with winter 2005/2006, PG&E, SoCalGas, and SDG&E were granted authority to hedge outside of their respective mechanisms, based on their respective hedging plans. Furthermore, these utilities requested and were granted a modification to

their incentive mechanisms so that all costs and benefits of their winter hedge programs are allocated directly to core customers without risk to shareholders.

On the other hand, we seek to explore whether the structure of the gas cost incentive mechanisms for each of the utilities is flexible enough to adequately insulate shareholders from significant risk. In addition, if hedging instruments are purchased in a liquid and transparent market, we could examine whether it is possible to design a program that compares the cost of a hedging program itself with market benchmarks, and puts the utility at some risk for variations from the benchmarks.

Each utility has a slightly different incentive mechanism based on their respective compilation of core assets. Each year the respective utility files an application or report with the Commission summarizing their results from the prior year with either a shareholder gain or loss. After the utility makes its filing, DRA conducts a full audit of each incentive mechanism and files its monitoring and evaluation report. The Commission then issues its decision or approval depending on the type of filing made by the utility. Each year since the inception of these incentive mechanisms, the Commission has found that it is in the best interest of ratepayers that these GCIMs and CPIMs continue.

This rulemaking is not intended to be a broad reexamination of the utilities' gas incentive mechanisms. Each year these incentive mechanisms go through an application process where there is an opportunity to propose modifications. In this rulemaking, we will focus more narrowly on whether hedging costs should be re-integrated into the existing incentive mechanisms, and if so, how. For example, we will examine whether the risks and benefits of hedging should continue to be allocated 100% to core customers and whether the

incentive mechanism design should be modified in some manner to recognize a decrease in shareholder risk.

We invite parties to provide comments if they feel that ratepayers could benefit from a certain type of modification to the existing structure of the incentive mechanisms. The Commission invites parties to provide comments on whether a separate hedging incentive mechanism is beneficial. Such an incentive program would concentrate on the cost of running an effective hedging program, not the whether the hedge resulted in a gain or loss.

6. Category of Proceeding

The Commission's Rules of Practice and Procedure require that an OIR preliminarily determine the category of the proceeding and the need for hearing.¹⁸ As a preliminary matter, we determine that this proceeding should be categorized as ratesetting because our consideration and approval of the respondents' long-term plans will establish mechanisms that in turn impact respondents' rates. As stated previously, we may hold evidentiary hearings as part of our effort to create a consistent hedging policy.

After the prehearing conference (PHC) in this matter, the assigned Commissioner will issue a scoping ruling making a final category determination. This final determination is subject to appeal as specified in Rule 7.6.

7. Schedule

We shall solicit initial comments to be due 30 calendar days after the effective date of this OIR, focusing on procedural and scoping issues for the entire proceeding. Reply comments shall be due 15 calendar days after the initial

¹⁸ Rule 7.1(d).

comments are due. Any party filing procedural comments shall address (1) the need for hearings, (2) the preliminary scope and timetable for this proceeding as described in this order, and (3) categorization of the proceeding.

We shall promptly schedule a PHC after review of parties' preliminary procedural comments at which time a further schedule for the proceeding shall be addressed. We expect to conclude this proceeding within 18 months.

8. Parties and Service List

Since our order names PG&E, SDG&E, SoCalGas, and Southwest Gas respondents to this rulemaking, by virtue of that fact they will appear on the official service list. For purposes of an initial service list for this proceeding, we shall utilize the R.04-01-025 service list until a ruling is issued notifying parties of a new service list.

We will also serve this order on the service lists for the following related proceedings: A.00-06-023; A.02-10-040; R.04-01-025; and A.06-08-026. Interested persons that are not already on the R.04-01-025 service list will have 20 days from the date of mailing of this OIR to submit a request to be added to the service list for this proceeding in accordance with the procedure prescribed in the Ordering Paragraphs below.

Persons on the service list should notify the Process Office of any subsequent address changes or if they wish to be removed from the list. Any other problems or questions about the service list after it is posted on the Commission's web site should be brought to the attention of the assigned ALJ. The service list will be updated in accordance with the described procedures, consistent with Rule 2.3.

Any person interested in participating in this proceeding who is unfamiliar with the Commission's procedures should contact the Commission's

Public Advisor's Office in Los Angeles at (213) 576-7055, (866) 849-8390 (toll free) or in San Francisco at (415) 703-2074, (866) 849-8390 (toll free), or (866) 836-7825 (TTY), or send an e-mail to public.advisor@cpuc.ca.gov

9. Requirements for the Filing and Service of Documents

There are different types of documents participants may prepare in this proceeding. Each type of document involves different obligations with respect to filing and service. Parties must file certain documents as required by the Rules or in response to rulings by the assigned Commissioner and/or the ALJ. All formally filed documents must be filed with the Commission's Docket Office and served on the service list for the proceeding. Article 1 of the Rules contains the Commission's filing requirements. Resolution ALJ-188 sets forth the interim rules for electronic filing, which replaces only the filing requirements, not the service requirements. Parties are encouraged to file electronically whenever possible as it speeds processing of the filings and allows them to be posted on the Commission's website. More information about electronic filing is available at <http://www.cpuc.ca.gov/efile/static.htm>.

Other documents, including prepared testimony, if any, are served on the service list but not filed with the Docket Office. We will follow the electronic service protocols adopted by the Commission in Rule 1.10 of the Commission's Rules of Practice and Procedure for all documents, whether formally filed or just served. This Rule provides for electronic service of documents, in a searchable format, unless the appearance or state service list member did not provide an e-mail address. If no e-mail address was provided, service should be made by United States mail. In this proceeding, e-mail service shall be made concurrently on ALL persons on the service list for whom an e-mail address is available,

including those listed under “Information Only.” Parties are expected to provide paper copies of served documents upon request.

Any e-mail communications to the Commission about this proceeding should include a brief description of the topic of the communication. Paper format copies, in addition to electronic copies, shall be served on the assigned Commissioner and the ALJ.

10. *Ex Parte* Communications

This proceeding is subject to Rule 8.2, which specifies standards for engaging in *ex parte* communications and the reporting of such communications. Because we have preliminarily categorized this proceeding as ratesetting, pursuant to Rules 8.2(c) and 8.3, *ex parte* communications are subject to advance notice and reporting requirements.

Therefore, **IT IS ORDERED** that:

1. A rulemaking is initiated on the Commission’s own motion to address the gas utilities’ incentive mechanisms and the treatment of hedging under those incentive mechanisms.
2. California’s major natural gas public utilities, Pacific Gas and Electric Company (PG&E), San Diego Gas & Electric Company (SDG&E), Southern California Gas Company (SoCalGas) and Southwest Gas Corporation (Southwest Gas), are made Respondents to this proceeding.
3. The Executive Director shall cause this Order Instituting Rulemaking (OIR) to be served on Respondents and on the service lists for Application (A.) 00-06-023, A.02-10-040, R.04-01-025 and A.06-08-026.
4. An initial service list for this proceeding shall be created by the Process Office and posted on the Commission’s website (www.cpuc.ca.gov). The initial

service list for this proceeding shall be the R.04-01-025 service list, which shall be used until a ruling is issued notifying parties of a new service list.

5. The issues to be considered in this proceeding are as set forth in the Preliminary Scoping Memo Section of this OIR.

6. Any additional persons or entities not on the list in R.04-01-025, but who wish to be placed on the new service list shall follow the directions below.

- (a) Appearance category. Those who wish to participate in this proceeding as a party must contact the assigned administrative law judge in writing, by email (trp@cpuc.ca.gov) or at CPUC, 505 Van Ness Avenue, San Francisco, CA 94102 and describe their interest in the proceeding, indicate how the person or entity intends to participate, and list all relevant contact information (name; person or entity represented; mailing address; telephone number; email address). By providing an email address, a party consents to service of documents by email.
- (b) Information-only category or state-service category. Those who intend only to monitor this proceeding, must contact the Commission's Process Office in writing, by email at (Process_Office@cpuc.ca.gov) or at CPUC, Process Office, 505 Van Ness Avenue, San Francisco, CA, 94102), specify the service category desired and list the pertinent contact information.
- (c) Only one appearance on the service list shall be allowed per party. Any additional persons representing the same party shall be added to the information-only category.

7. The category of this rulemaking is preliminarily determined to be "ratesetting" as that term is defined in Rule 8.2(c) & 8.3 of the Commission's Rules of Practice and Procedure.

8. Respondents and other interested parties may submit comments on the scope of issues, categorization, need for hearing, and other procedural issues

within 30 calendar days after the effective date of this OIR. Reply comments shall be due 15 calendar days thereafter.

9. A prehearing conference shall be scheduled promptly following receipt of preliminary comments at which time a further schedule for the proceeding will be addressed.

10. The above-mentioned deadlines are preliminarily approved and adopted, but may be changed, if necessary, by an assigned Commissioner Ruling or an ALJ Ruling.

This order is effective today.

Dated June 26, 2008, at San Francisco, California.

MICHAEL R. PEEVEY
President
DIAN M. GRUENEICH
JOHN A. BOHN
RACHELLE B. CHONG
TIMOTHY ALAN SIMON
Commissioners