DOCKET

09-IEP-1J

DATE MAR 10 2009

RECD. MAR 10 2009

NATURAL GAS PROCUREMENT BY UTILITIES

Lana Wong

Electricity Analysis Office
Electricity Supply Analysis Division
California Energy Commission

DRAFT STAFF PAPER

February 2009
CEC-200-2009-003-SD

Wong, Lana. *Natural Gas Core and Non-Core Procurement 2009*. California Energy Commission. CEC-200-2009-003-SD

Table of Contents

List of Figures

Page

Executive Summary

How Utilities Procure Natural Gas

Natural gas prices reached over $13.00 per million British thermal units (MMBtu) at the Henry Hub during the summer of 2008, prices not seen since 2005. Natural gas prices have since dropped to the $4.00 per MMBtu range. California Energy Commission (Energy Commission) staff has undertaken analysis to understand the impact of fluctuating market prices on the gas utilities and ratepayers. More specifically, are the gas utilities and ratepayers exposed to these market prices? In this effort, staff analyzed data, conducted literature research, and interviewed representatives from the gas utilities, the California Public Utilities Commission (CPUC), and the Division of Ratepayer Advocates (DRA).[1]

The CPUC and the DRA indicate that the utilities tend to procure natural gas under short-term monthly contracts.[2] The gas cost incentive mechanisms established by the CPUC were designed to encourage utilities to procure natural gas at or below a benchmark price. The benchmark price is based on a basket of monthly and some daily indices. If the utilities procure natural gas at or below the benchmark, they will be able to recover these costs from ratepayers. The utilities will also share in the savings with ratepayers if the cost-to-benchmark differences are below a certain threshold (the deadband around the benchmark), or will be penalized if their costs are above a certain threshold.

Figure 1 shows Pacific Gas and Electric (PG&E) weighted average cost of gas (WACOG) compared to the PG&E Citygate average bidweek index. PG&E's weighted average cost of gas tracks the PG&E Citygate average bidweek price. **Figure 2** shows Southern California Gas Company's (SoCalGas) retail procurement charge compared to the SoCalBorderAvg average bidweek price. Though SoCalGas' weighted average cost of gas is not publicly available, staff has determined that their procurement charge tracks the SoCalBorderAvg average bidweek price. The monthly procurement charge is an estimate and is the gas commodity component of the retail rate charged to ratepayers plus various adders including reservation charges, franchise fees, uncollectible expenses, and brokerage fees. The data suggests that the utilities are buying gas for their core customers at the monthly

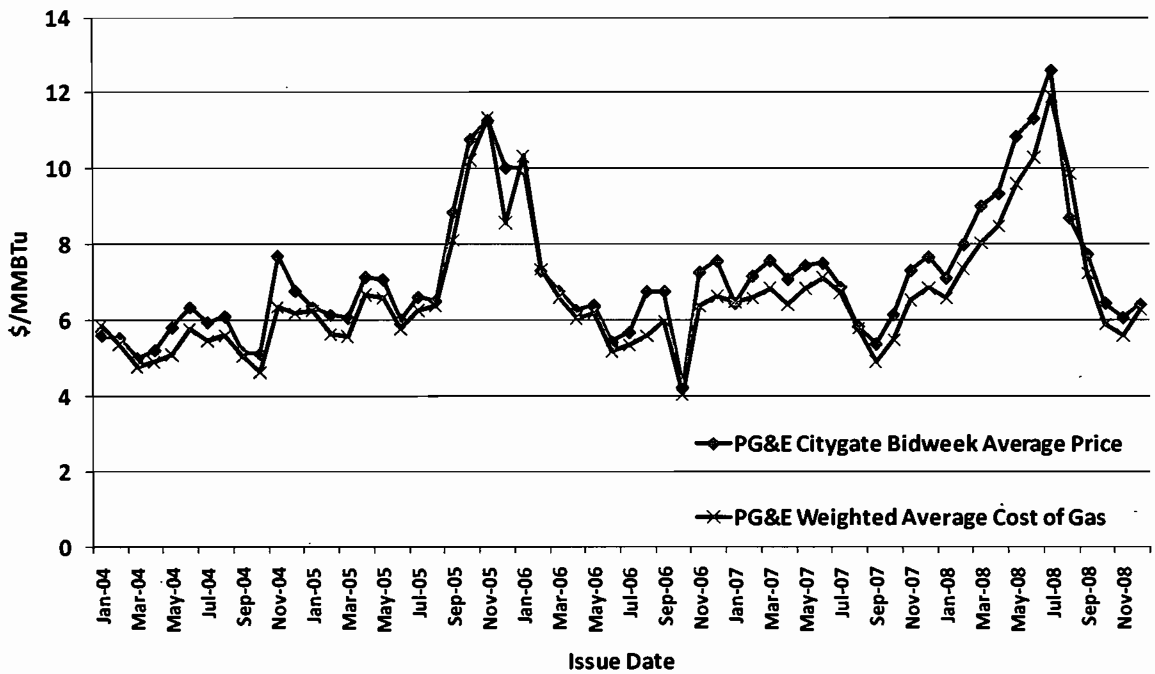
---

[1] Energy Commission staff spoke with Richard Meyers of the CPUC on December 5, 2008, and Ramesh Ramchandani of CPUC's The Division of Ratepayer Advocates (DRA) on January 8, 2009. Staff also spoke with Don Peterson of PG&E on December 4, 2008, at the monthly Natural Gas Working Group meeting. Staff has had further conversations with Don Petersen, who has solicited the assistance of PG&E's gas procurement group. Scott Muranishi of PG&E's gas procurement group provided further information on PG&E's gas procurement practices. Staff spoke with Herb Emmrich of Sempra Utilities, who provided information on SoCalGas procurement practices.

[2] In this paper, *short-term* will be defined as terms of less than one year, and *long-term* will be defined as periods of greater than one year.

index. This finding shows that ratepayers are not immune to the volatility or the prices in the marketplace, but the gas utilities do employ limited hedges to protect ratepayers from natural gas price spikes during the winter.

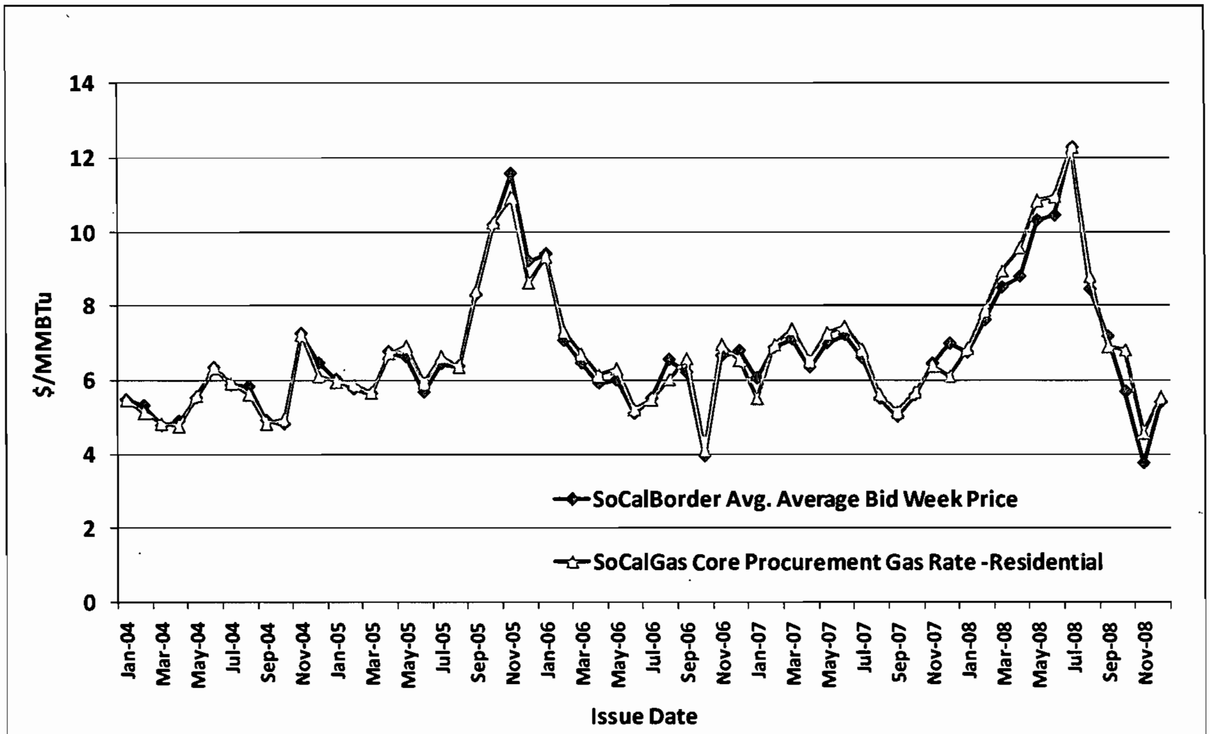
Figure 1: Price Comparison of PG&E Weighted Average Cost of Gas to PG&E Citygate Bidweek Prices ($/MMBtu)



Note 1: Monthly bidweek data includes transactions done at the end of each month for gas to be delivered for the entire following month.
Note 2: The weighted average cost of gas includes interstate pipeline volumetric commodity charges and excludes all other procurement related charges.

Source: NGI for bidweek prices and PG&E's website http://www.pge.com/nots/rates/tariffs/rateinfo.shtml#GRF for the commodity prices.

Figure 2: SoCalGas Price Comparison ($/MMBtu)



Note 1: Monthly bidweek data includes transactions done at the end of each month for gas to be delivered for the entire following month.

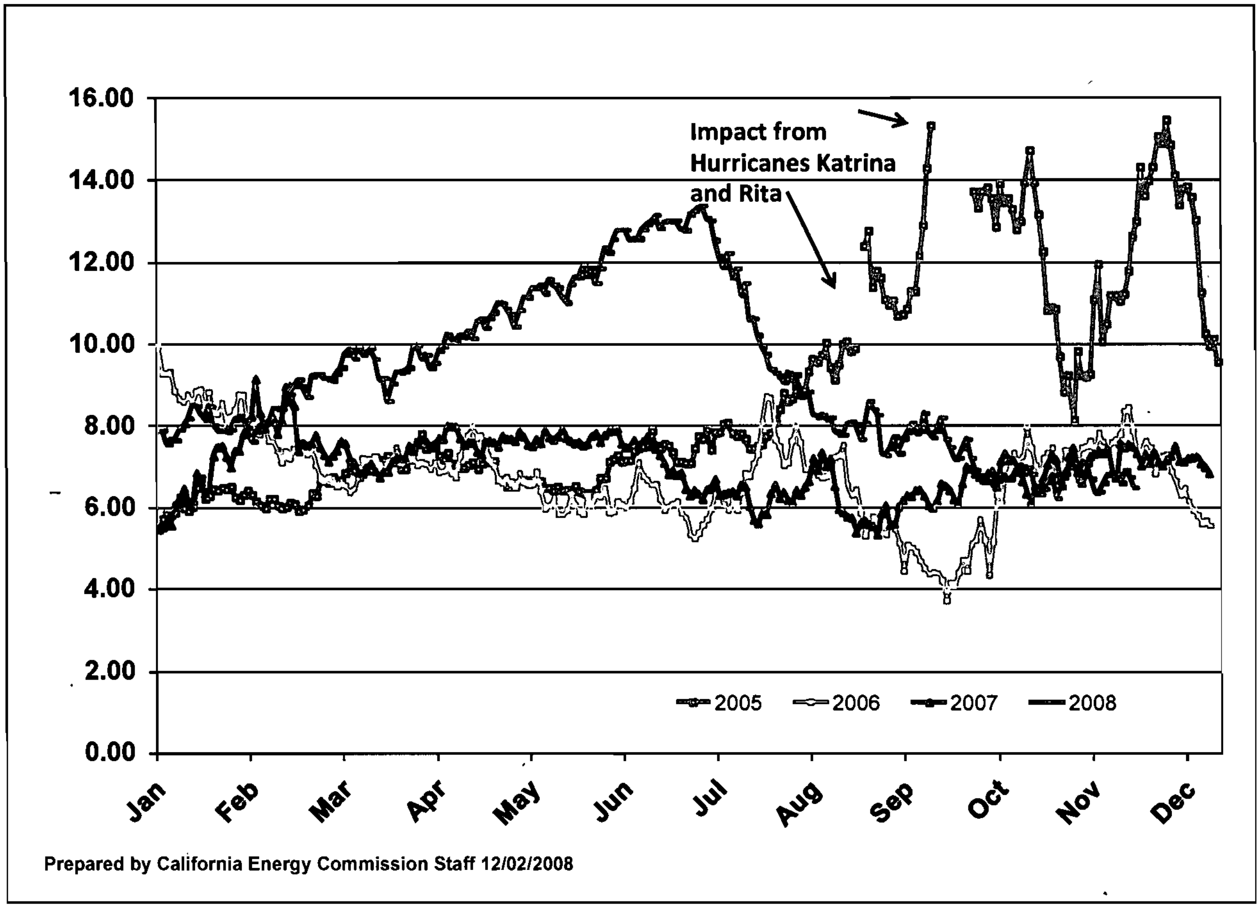
Note 2: The residential core procurement gas price is comprised of the weighted average cost of gas including reservation charges for interstate pipeline capacity charges and carrying costs of storage, franchise fees and uncollectibles, brokerage fees, balancing account charges, and adjustment for the gas cost incentive mechanism (GCIM) reward/penalty.

Source: NGI and SCE website, www.SCE.com.

Introduction

Natural gas prices have been volatile over the past several years. **Figure 3** shows Henry Hub daily spot prices during the past four years. Daily spot prices can be affected by constraints, such as weather, speculation, high or low demand, availability of pipeline capacity, in-field production problems, storage injection or withdrawal, and so forth. For example, Hurricanes Katrina and Rita contributed to the price spikes that occurred in 2005. Natural gas prices in 2008 increased to over $13.00/MMBtu in July 2008, some believe due to speculation, but fell below $5.00/MMBtu by year's end. Pipeline constraints out of the Rockies to the east that occurred in the fall of 2008 caused daily spot gas prices to drop to the $1.00/ MMBtu range at some trading points in the west. On the other hand, constraints that occur in New York can cause prices to increase several dollars over nearby Chicago. Cold weather in the East can cause price spikes to ripple all the way to California. Given this volatility in gas prices, staff has been asked whether natural gas utility customers are exposed to these high natural gas prices. Furthermore, do natural gas utilities enter into price contracts that insulate customers from natural gas price spikes? This paper will examine the issues surrounding how natural gas utilities procure natural gas.

Figure 3: Henry Hub Daily Spot Prices



Source: NGI data

Background on Natural Gas Utilities

The two main natural gas utilities procuring natural gas supply for use in California are PG&E and SoCalGas. In April 2008, SoCalGas began procuring natural gas for San Diego Gas & Electric (SDG&E) core customers. SoCalGas/SDG&E is the principal distributor of natural gas in Southern California while PG&E is the principal distributor of natural gas in Northern California. Both companies provide natural gas procurement, transportation, and storage services.

In 1988, the CPUC split gas utility customers into two main groups: core and noncore customers. Core customers are primarily residential and small commercial customers who typically receive all services bundled from the regulated natural gas utility. The bundled services include procurement, transmission, storage, distribution, metering, and billing. Noncore customers are primarily large commercial, industrial, and electric generation customers who mainly procure their own natural gas supplies. Noncore customers may use the utility's transmission and distribution system and other services on an unbundled cost basis. The utilities are obligated to provide storage for their core customers only. Noncore customers can take storage from the utility, but must contract and directly pay for this service.

Residential core customers are by far the most numerous with over 10.3 million residential customers who receive delivery of natural gas from a regulated utility. The cost of natural gas to residential customers is comprised of two primary components: procurement of natural gas (the commodity cost of natural gas); and transmission, storage and distribution costs (the cost of delivery over interstate and intrastate pipelines). Transmission, storage and distribution charges have been relatively stable and do not exhibit the volatility that the commodity prices do. This paper will focus on residential core customers since they rely on the utility for providing natural gas services.

Options for Procuring Natural Gas

Utilities have different options to procure natural gas:

- Multi-month contracts
- One-month supply during bidweek
- Daily spot market purchase
- Storage withdrawal
- Financial Instruments

Multi-Month

The multi-month contracts can be short-term, such as one- to two-month contracts, or long-term with periods greater than one year. This type of contract can be an agreement between the utility and marketer or a utility and producer of natural gas. No major gas industry publication develops any reported indices for transactions with terms longer than one month. The CPUC and the DRA have indicated that the utilities tend to procure natural gas using short-term contracts and that there is limited use of long-term price contracts[3]. DRA actually opposes a policy that encourages utilities to enter into long-term ("fixed-price") gas procurement contracts because these contracts may carry enormous risks[4]. These seasonal long-term contracts may be volume contracts with the price of natural gas for each month tied to a monthly index for a specific receipt point, rather than being a fixed price contract.

One-Month Supply During Bidweek

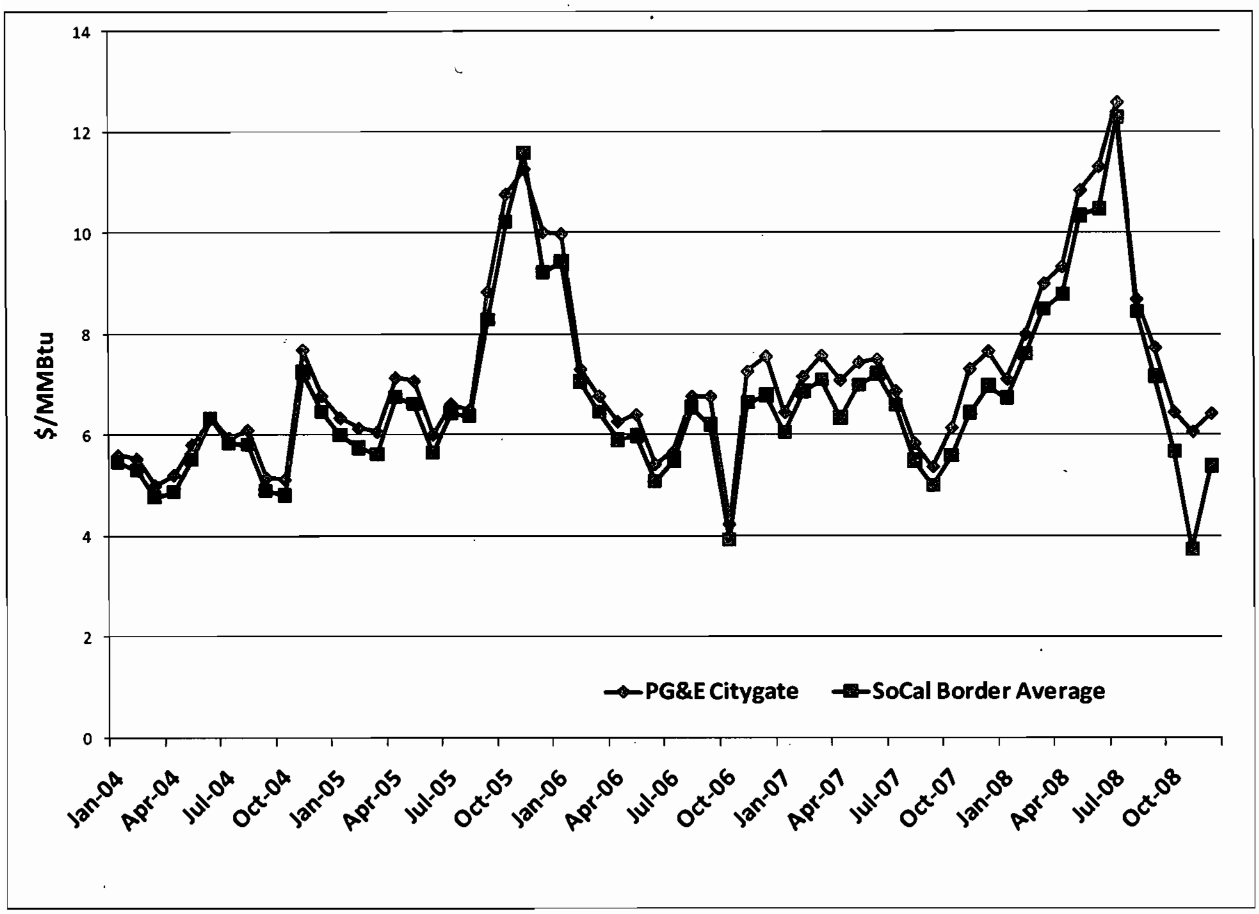
Bidweek occurs during the last week of every month where buyers and sellers contract for physical delivery of natural gas for the following month at a fixed priced. These types of arrangements may be considered spot monthly fixed rate contracts. The largest volume of trading in the natural gas market occurs during bidweek when producers are trying to sell their core production, and utilities are trying to buy for their upcoming monthly core natural gas needs. Major industry publications, such as *Natural Gas Intelligence* (NGI), report wholesale prices that occurred during bidweek. Per NGI, monthly bidweek data includes transactions completed at the end of each month for gas to be delivered for the entire following month. The bidweek data available on NGI includes the survey start date and end date; low, high, and average prices; volume; and number of deals.

[3] Energy Commission staff spoke with Richard Meyers of the CPUC on December 5, 2008, and Ramesh Ramchandani of CPUC's the DRA on January 8, 2009, both of whom indicated that utilities purchase gas on a short-term monthly basis. PG&E has confirmed that the majority of their gas supply portfolio is under one-year and multi-month contracts and a lesser amount under one-month contracts, all of which may be priced using monthly or bidweek indices. At the monthly Natural Gas Working Group held on December 4, 2008, at the Energy Commission, Herb Emmrich of Sempra Utilities indicated that it purchases gas priced to the index.

[4] D.07-11-001, Comments of the Division of Ratepayer Advocates, January 24, 2008.

Figure 4 shows the bidweek average monthly natural gas prices for PG&E Citygate[5] and SoCalBorderAvg[6] pricing points. The average prices set during bidweek are commonly the values used in physical contracts.

Figure 4: Bidweek Average Monthly Natural Gas Prices ($/MMBtu) 2004 - 2008



Source: NGI data

Daily Spot Market Purchases

Daily spot market purchases are used for short-term physical purchases to be delivered the next day or over a couple of additional days. NGI also reports wholesale prices that occurred daily throughout the month. The daily spot market purchases available on NGI

---

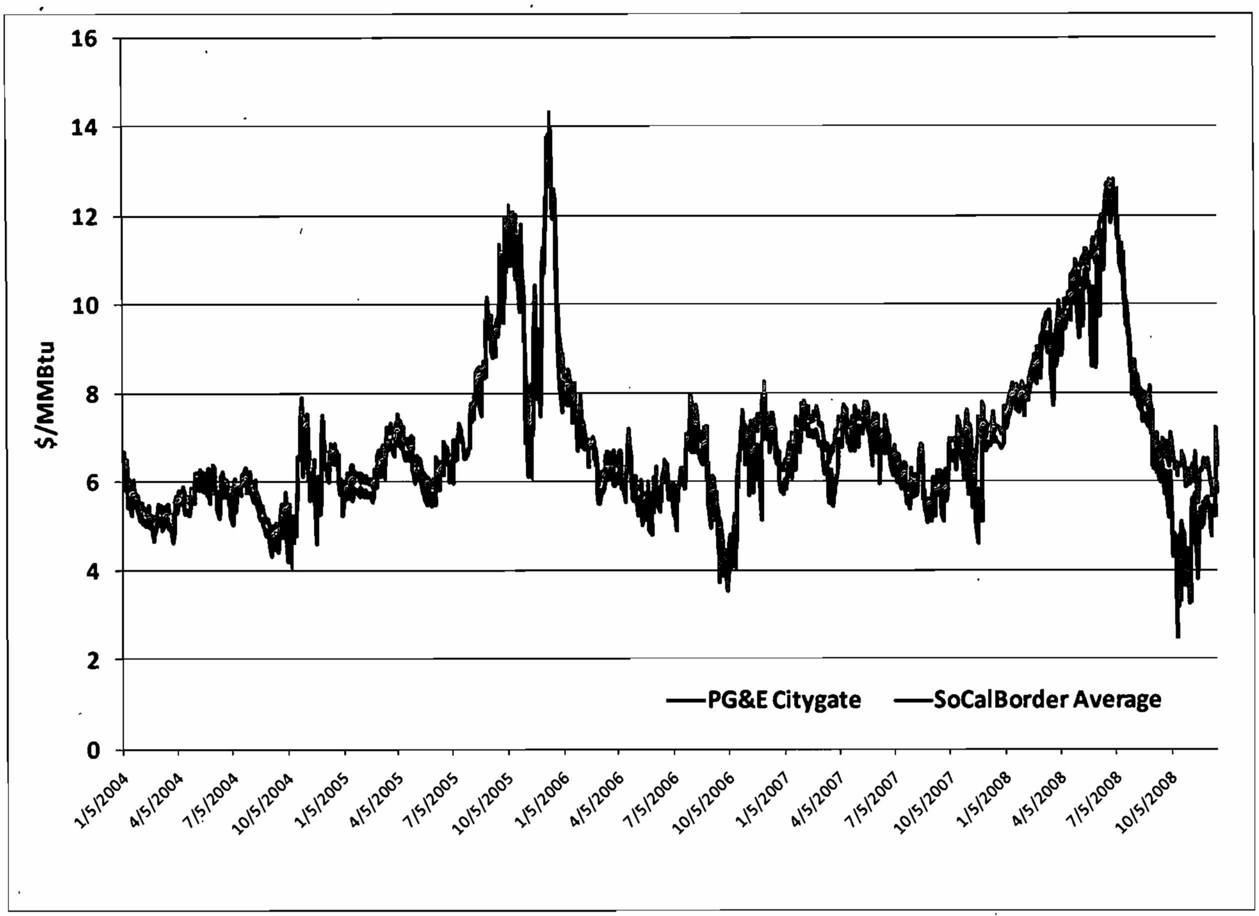
[5] PG&E Citygate represents the price of natural gas just prior to entering PG&E gas distribution network.

[6] SoCalBorderAvg represents the price of natural gas prior to entering SoCalGas gas distribution network and excludes some minor intrastate transmission charges.

include the trade date, delivery start, and end date; low, high, and average prices; volume; and number of deals.

Figure 5 shows the daily spot natural gas prices for PG&E Citygate and SoCalBorderAvg pricing points. These are the primary receipt points for both PG&E and SoCalGas.

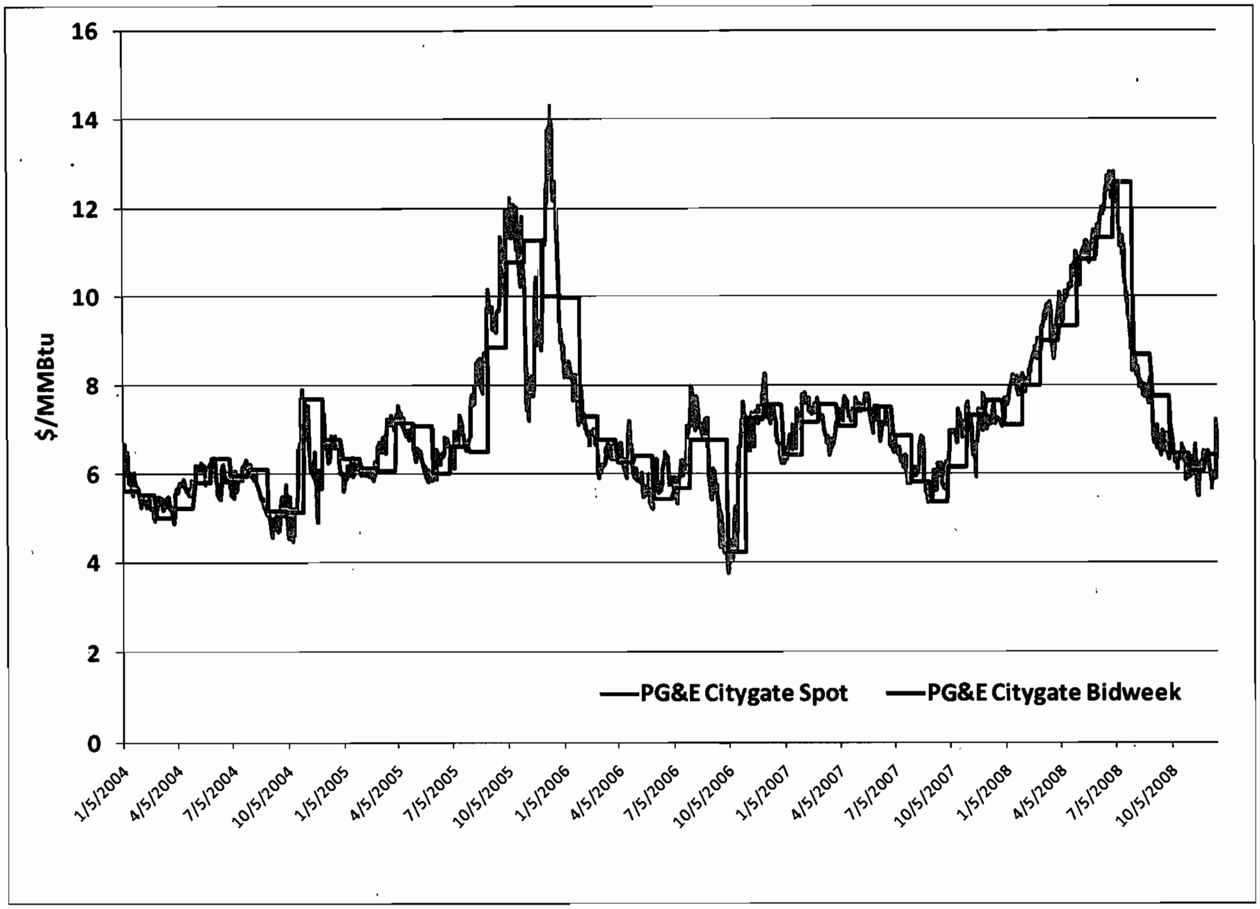
Figure 5: Daily Spot Market Natural Gas Purchases ($/MMBtu) 2004 - 2008



Source: NGI data

Figure 6 shows how bidweek prices compare to daily spot market purchases for PG&E Citygate, and **Figure 7** shows the same data for SoCalBorderAvg. In constructing the charts, the daily prices for bidweek are the same for every day of the month while the daily spot prices adjust each day. Therefore, the shape of the bidweek price is shown in a step-wise fashion in the chart. The data shows that the bidweek and daily spot prices are equally volatile and that they tend to track one another; the daily spot prices may be higher or lower than bidweek prices, but they exhibit a similar price pattern. The CPUC has indicated that the utilities purchase very little on the daily spot market.[7] Utilities do not rely solely on daily spot market purchases to fulfill their needs because relying on spot purchases could lead to supply shortages. Utilities tend to contract ahead for their volume needs and to balance their fluctuating daily core demand by purchasing on the spot market or by withdrawing from storage. Utilities may also purchase on the spot market because of weather. If a cold snap hits, a utility may prefer to purchase from the spot market rather than pull from storage, saving storage for another day.

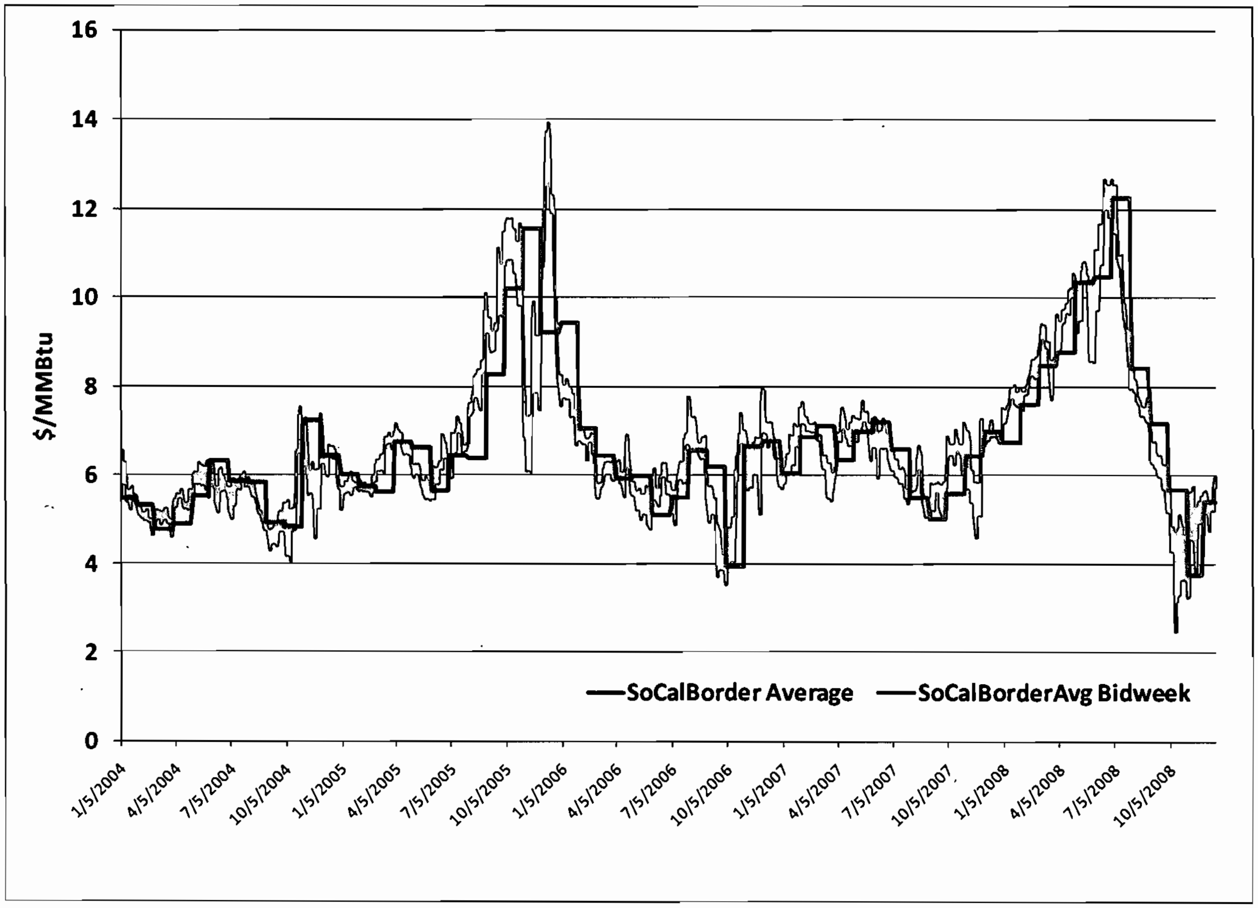
Figure 6: PG&E Citygate Price Comparison of Monthly Bidweek Versus Daily Spot Prices 2004 - 2008



Source: NGI data

[7]Staff does not have exact percentages of quantities contracted because contract information is confidential, but information is based on discussions with Richard Meyers of the CPUC.

Figure 7: SoCalGas Price Comparison of Monthly Bidweek Versus Daily Spot Prices 2004 - 2008



Source: NGI data

Storage Withdrawal

Storage serves multiple roles. It serves a physical need of the system as well as offering a financial hedge. The gas system within California is not designed to meet all winter peak demand from flows on the pipeline system coming into California. Winter peak demand is partially met by storage. The natural gas utilities have an obligation to reliably serve their core customers without interruption. To ensure that reliability is met, the natural gas utilities are required to fill their storage facilities to a certain level (a portion of their core demand) by November 1, the beginning of the winter peak season. PG&E is required to put 33 billion cubic feet (Bcf) into storage by November 1 while SoCalGas/SDG&E has two requirements, a mid-year requirement of 51 Bcf by July 31 and winter peak requirement of 79 Bcf by November 1. Utilities can withdraw from storage to meet their winter peak season gas demands.

Storage also offers a physical hedge against volatile gas prices and is useful when arbitrage opportunities present themselves. When gas prices are really low, a utility can put more gas into storage. For example, the daily spot price at SoCalBorderAvg pricing point dropped to $2.51/ MMBtu on October 13, 2008. SoCalGas could opt to inject more into storage on such a day than they otherwise would have if prices were in the more usual $4.50 to $5.00/MMBtu range. If gas prices spike, a utility could choose to withdraw from storage.

PG&E storage capacity is more limited and less flexible than SoCalGas storage capacity. PG&E storage capacity is primarily available only for core customers, while SoCalGas storage capacity is available for core customers as well as non-core customers. There are other independently owned storage facilities in Northern California that are available for noncore use. PG&E's winter withdrawal occurs during November through March, while summer injection occurs during April through October. PG&E has about 98 Bcf of storage capacity. Given the limitations of PG&E's system, they need to make regular injections into storage, or they will not meet their winter peak demand by November 1. SoCalGas/SDG&E storage is more flexible than PG&E with 131.1 Bcf of storage capacity; about 79 Bcf is allocated to core residential, small industrial and commercial customers. About 5 Bcf is used for system balancing, and the remaining capacity is available to noncore customers[8]. Additionally, because of its higher injection capability over PG&E, it has more flexibility to operate its storage facilities. As a result, SoCalGas/SDG&E has greater ability to take advantage of arbitrage opportunities and more flexibility to use storage as a physical hedge against high gas prices than PG&E may have.

Financial Instruments

Utilities can use financial instruments to hedge against winter price spikes. Financial hedges can be a form of price insurance used to protect customers from excessively high and volatile natural gas price swings. The following is a list of types of hedges:

- Physical fixed price contracts.
- Option contracts to purchase or sell gas at a predetermined price.
- Futures contracts for future delivery of a fixed amount of gas at a fixed price.
- Financial swaps to exchange two cash flows on a fixed price and a spot reference price.

There is a cost with obtaining a hedge, such as brokerage fees/commissions, and there could be additional costs from the resulting position of the hedge, whether it is in the money or out of the money. 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. Hedging is designed to reduce risk, but there is risk inherent in hedging.

---

[8]*2008 California Gas Report*, California Gas and Electric Utilities.

Regulatory Structure and Incentive Mechanisms

Natural gas utilities typically file requests at the CPUC to seek recovery of the costs incurred for buying the gas commodity for their core customers, subject to gas cost incentive mechanisms adopted by the CPUC. The gas cost incentive mechanisms are only pertinent to a utility's core gas portfolio and do not apply to noncore customers. The utilities are allowed to pass through gas purchase costs directly to its core customers. The utility may file an Advice Letter to the CPUC monthly regarding their purchase costs that either lower or raise the commodity component of its rates to their core customers and others who elect to receive full bundled service from the utility.

In the early 1990s, utilities procured natural gas for their customers using fixed price contracts. They estimated their gas purchase costs for the coming year and used that as a basis for the commodity component of the rates. These contracts were subject to "reasonableness reviews" by the CPUC. Many of these contracts were out of the money, meaning that they were priced above the current market prices. In the mid-1990s, when prices became more volatile and the utility had huge balancing accounts (a system to track expenses over and under the estimate), the CPUC shifted to the current system of gas incentive mechanisms. The gas cost incentive mechanisms are designed to protect core customers from excess purchase costs.

An overview of the incentive mechanism provided on the Division of Ratepayer Advocates' website states:

> Gas procurement incentive mechanisms were first implemented in the mid-1990s. These mechanisms replaced the highly litigious and time-consuming "reasonableness reviews" that prevailed prior to the mid-1990s. The goals of the incentive mechanisms were three-fold: (1) to align customer and shareholder interests; (2) to measure utility performance relative to a market-based benchmark; and (3) to reduce the regulatory burden. In developing the incentive mechanisms, DRA collaborated with each utility so that mechanisms were designed to strike a balance between risk and reward while providing utilities an incentive to acquire gas at the lowest possible cost. The mechanisms have been modified over time to accommodate market and regulatory changes.
>
> The Performance Based Ratemaking (PBR) mechanism was adopted for SDG&E in 1993. The Gas Cost Incentive Mechanism (GCIM) was adopted for SoCalGas in 1994. And finally, in 1997, the Core Procurement Incentive Mechanism (CPIM) was adopted for PG&E. More recently, in 2005, a gas cost incentive mechanism was also adopted for Southwest Gas. While the basic structure is the same for the gas procurement incentive mechanisms, each utility's mechanism incorporates its own unique facets. All mechanisms have deadbands, where ratepayers receive 100% of any gains or incur 100% of the losses within the deadband around the benchmark.

If a utility procures gas at prices lower than the benchmark, then "savings" are realized. Ratepayers and shareholders share these savings. On the other hand, if the utility procures gas at prices higher than the benchmark, then losses are realized. In this instance, ratepayers and shareholders share these losses. Benchmarks are based on gas price indices published by industry journals such as Inside FERC and Gas Daily[9].

The incentive mechanisms provide an overarching guideline for the utilities' procurement practices. In April 2008, SoCalGas began procuring natural gas for SDG&E core customers, so their PBR has been replaced with the GCIM. Utilities can optimize their assets to offset overall costs. The utilities do not want to incur losses, so they have an incentive to procure gas at prices at or below the benchmark. A deadband of 2 percent above and 1 percent below the benchmark provides a cushion to the utilities where sharing between shareholders and ratepayers occurs when costs are outside of the deadband. The incentive mechanisms are customized to each utility and are a complex calculation, but a key component of the incentive mechanism is the benchmark calculation. The benchmark is short-term oriented and is a critical metric to determining the gains or losses for the shareholders and ratepayers.

PG&E's Benchmark

Some of the salient features of PG&E's CPIM include the use of a sequencing formula to establish the benchmark.

Key attributes of CPIM include:

- Use of published wholesale market gas price indices.
  - Monthly gas price indices tied to firm pipeline capacity holdings.
  - Daily PG&E Citygate gas price index used on high demand days when firm capacity holdings are exceeded.
- The annual commodity benchmark is the sum of 365 daily benchmarks.
  - At the end of the year, all daily gas costs and all daily revenues are summed. If the net costs fall within the deadband around the commodity benchmark, they are fully recovered from ratepayers.

[9]http://www.dra.ca.gov/DRA/energy/gas/GPIM.htm

- Least-cost sequencing by supply basin.
  - Sequence means the order in which CPIM assumes that PG&E should buy gas and use storage, based on least cost.

The CPIM includes brokering revenues and allows for sales and a small reward for capacity discounts. The CPIM defines the storage schedule and allows for some storage arbitrage. PG&E's shareholder reward is capped at the lower of $25 million or 1.5 percent of total annual gas commodity costs.

SoCalGas/SDG&E Benchmark

For SoCalGas/SDG&E's GCIM, actual basin purchase volumes are used to establish the benchmark. On an annual basis, the GCIM compares the actual cost of the Utility Gas Procurement Department's purchases to an annual benchmark budget. The annual benchmark budget is the sum of 12 monthly benchmark budget amounts. The monthly benchmark budget is the sum of monthly benchmark gas commodity costs, monthly benchmark commodity transportation costs, and monthly benchmark transportation reservation charges. As previously mentioned, the transportation charges have not been volatile like the commodity charges, so the commodity charges are the focus of this paper.

Monthly benchmark gas commodity costs are calculated at the mainline for interstate purchases and the border for border purchases. The monthly benchmark gas commodity cost is the product of the mainline gas commodity reference price times the volume purchased at the mainline plus the product of the border gas commodity reference prices times the volume purchased at the respective border locations. Details of the commodity index calculation are as follows:[10]

- The mainline gas commodity reference price consists of the weighted average of published indices from two gas industry publications for the mainline trading points for each production basin from which the Utility Gas Procurement Department procures its gas supplies. It equals the product of pipeline and basin weights applied to pipeline and basin specific indices reported in each of the publications. Each weight equals the ratio of the actual gas purchased from a specific pipeline/basin to the total gas purchased during the month by the Utility Gas Procurement Department at the mainline. Since the Utility Gas Procurement Department's purchases from the Anadarko basin are minimal, these volumes are included in the Utility Gas Procurement Department's Permian purchases for purposes of developing weighting factors. If one publication does not report an index value for a specific pipeline/basin combination for a given month, the Mainline Gas Commodity Reference Price will use the corresponding index value from the other publication.

---

[10] Southern California Gas Company Advice Letter No. 3905, filed September 30, 2008, and effective October 1, 2008.

- The border gas commodity reference prices are based on the simple average of two published indices. The Southern California Border Average indices will be used for border purchases, including purchases from California production, and purchases made at the California border (with the exception of volumes purchased and sold at non-SoCalGas receipt points).
- The border gas commodity reference price for these non-SoCalGas receipt points will be the simple average of published indices at each of these respective receipt points. Transactions at non-SoCalGas receipt points (for example, PG&E-Topock, Mojave-Topock, Malin, and so forth) will be tracked separately.

The GCIM allows for core Secondary Market activities and sales. Storage target and minimums are also set in advance under the GCIM. The SoCalGas shareholder reward is capped at 1.5 percent of actual annual gas commodity costs.

Hedging and the Incentive Mechanisms

Utilities can employ financial hedges to protect against winter price spikes. Before 2005, the cost of financial hedging was included in the incentive mechanisms. In 2005, gas prices spiked due to Hurricanes Katrina and Rita, raising utility concerns about the upcoming winter gas prices. PG&E filed an emergency petition with the CPUC in the fall of 2005 asking approval to hedge much of its then-unhedged winter demand. The hedges were to serve as insurance to their core customers or ratepayers and protect against high winter natural gas prices. All benefits and costs from the additional hedging were to accrue solely to ratepayers and flow through to ratepayers outside the incentive mechanisms. There would be no sharing of gains or losses accruing to shareholders. Shortly after PG&E's petition was approved, SoCalGas and SDG&E filed similar petitions to increase their hedging activities and to account for the benefits and costs outside of the incentive mechanisms, again meaning that all costs and benefits accrue solely to ratepayers.

The utilities believe that the existing incentive mechanisms (before 2005 when hedging costs were included in the incentive mechanisms) do 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 and that the risk/reward is asymmetric to the benefit of ratepayers, the utilities requested that costs of the proposed hedging plans for that 2005 winter be removed from the incentive mechanisms. Since 2005, the CPUC has continued to approve the cost of hedging to be accounted for outside of the incentive mechanisms, so the cost of hedging accrues solely to ratepayers without any risk to shareholders. See the "Issues" section for further discussion on hedging within the incentive mechanisms and the current CPUC proceeding, Rulemaking 08-06-025, to determine whether the utilities natural gas hedging plans can and/or should be incorporated into their existing gas cost incentive mechanisms.

Assessment of How the Utilities Procure Natural Gas

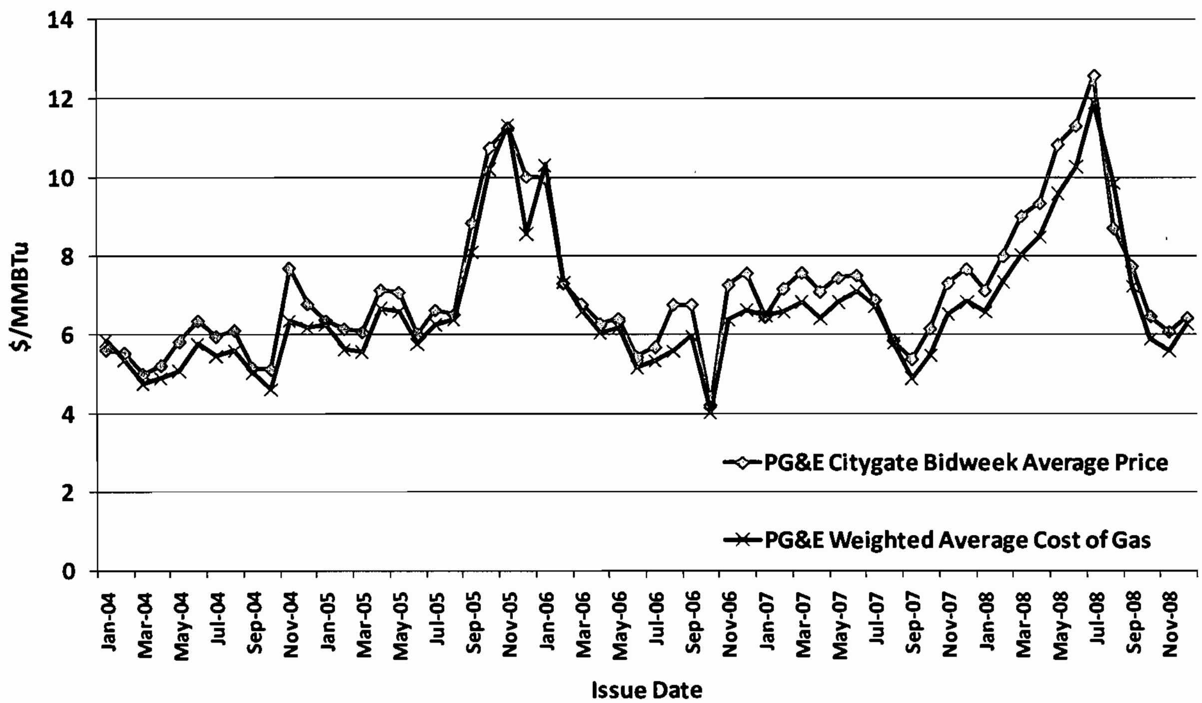
The gas utilities have different options for procuring natural gas as shown in the section "Options for Procuring Natural Gas," but the incentive mechanisms provide an overarching guide to how utilities procure natural gas. The benchmark index used to measure utility performance is based on short-term monthly and some daily indices. The bidweek monthly prices and daily spot market prices are used to calculate the benchmark. The incentive mechanisms encourage purchasing at or below the benchmark, but the mechanisms do not provide an incentive to provide price stability or risk management of gas prices. The incentive mechanisms provide no reasons to enter into long-term fixed price contracts since the benchmark is tied to monthly and daily indices.

In the current environment of adequate gas supplies, long-term contracts for the gas commodity are discouraged unless there are clear and distinct benefits to ratepayers, such as contracts priced below the index. As previously mentioned, the CPUC and DRA recommend that the utilities procure natural gas for core customers primarily on a short-term monthly basis. They enter into new monthly contracts by buying natural gas during bidweek. The specific contracts are not publicly available, so Energy Commission staff does not have access to the actual gas contracts entered into by the gas utilities. Though the contracts are not available, staff was able to obtain price data from the utilities' websites.

Figure 8 shows PG&E weighted average cost of gas (WACOG) compared to PG&E Citygate bidweek prices. The WACOG represents the commodity cost of gas including interstate pipeline volumetric commodity charges and excludes all other procurement related charges. The city gate price is for a commodity delivered into its system and includes additional costs, such as the transportation costs to this point. PG&E's WACOG tracks the PG&E Citygate bidweek prices[11]. The WACOG and the PG&E Citygate bidweek prices are highly correlated with a correlation coefficient of 0.97 for the past two years of data, indicating that they are almost perfectly correlated. A correlation coefficient of 1.0 indicates perfect correlation.

[11] PG&E has indicated that in a perfectly efficient natural gas market, PG&E's core WACOG is expected to track the PG&E Citygate average index. However, PG&E's core WACOG is formulated using basin prices, where PG&E buys most of its natural gas. Therefore, the resulting WACOG may not be highly correlated with the PG&E Citygate index. Staff reviewed the data and found a high correlation between WACOG and PG&E Citygate index.

Figure 8: Price Comparison of PG&E Weighted Average Cost of Gas to PG&E Citygate Bidweek Prices ($/MMBtu)



Note 1: Monthly bidweek data includes transactions done at the end of each month for gas to be delivered for the entire following month.
Note 2: The weighted average cost of gas includes interstate pipeline volumetric commodity charges and excludes all other procurement related charges.

Source: NGI for bidweek prices and PG&E's website http://www.pge.com/nots/rates/tariffs/rateinfo.shtml#GRF for the commodity prices.

In contrast to PG&E, SoCalGas WACOG is not publicly available.

Cost Recovery and Procurement Charge

The gas utilities have an obligation to serve their core customers, and in return they expect to recover their costs. The retail gas rate that is charged to core customers typically includes a procurement (commodity) component and a transportation component. The procurement component includes the purchase and sale of the natural gas commodity plus all of the other procurement related costs. The transportation component includes the local delivery of natural gas through large-diameter, high-pressure, long-distance pipelines, distribution costs of delivering natural gas from the city-gate to customers, and billing, metering, and other services. The utilities file monthly advice letters with the CPUC that identify the procurement rate changes for the next month. The procurement charge is an estimate and can be comprised of multiple items with the weighted average cost of gas being the largest component of the procurement charge. Approved hedging costs can also be a component of the utilities' procurement charge.

PG&E's procurement charges include:[12]

- Weighted average cost of gas – estimated for the current month
- Core brokerage fees
- Interstate pipeline capacity charge
- Intrastate backbone transmission charges
- Core firm storage
- Cycled carrying costs of gas in storage
- Franchise fees and uncollectible expenses
- Winter Gas Savings Program costs
- Hedging costs
- Shrinkage costs
- Balancing account charges or credits

SoCalGas/SDG&E procurement charges include, but may not be limited to:

- Weighted average cost of gas – estimated for the current month
- Core brokerage fee
- Interstate capacity charge
- Core firm storage
- Franchise fees and uncollectible expenses
- Access charges
- Gas cost incentive mechanism reward/penalty
- Core purchased gas account (CPGA) imbalance band adjustment – adjustments are made when the over or undercollection of gas costs through rates exceed a band of ±1 percent of the actual annual commodity gas purchases for the preceding 12-month period ending March 31

Balancing account activities can cause charges or credits to be applied to the procurement charge. For example, an undercollection in a prior month may be collected in future months

---

[12]Scott Muranishi of PG&E's gas procurement group provided a list of components that comprise their procurement charge.

by a short-term raise in the rates. Likewise, an overcollection could be distributed back to the ratepayer in terms of reduced rates over several months. The procurement charges are estimates of the gas costs. For example, the procurement charge for December 2008 is set in November 2008 through the monthly advice letter, based on an estimate of gas costs to serve the estimated demand. A true-up of costs is made, and any deviations are accounted for in future months.

PG&E and SoCalGas/SDG&E procurement charges are publicly accessible on their websites. In addition, PG&E also provides their weighted average cost of gas. As previously mentioned, SoCalGas/SDG&E considers the weighted average cost of gas confidential, and the only detailed breakout of expenses provided in their public version of the advice letter is the brokerage fee of about $0.02/MMBtu.

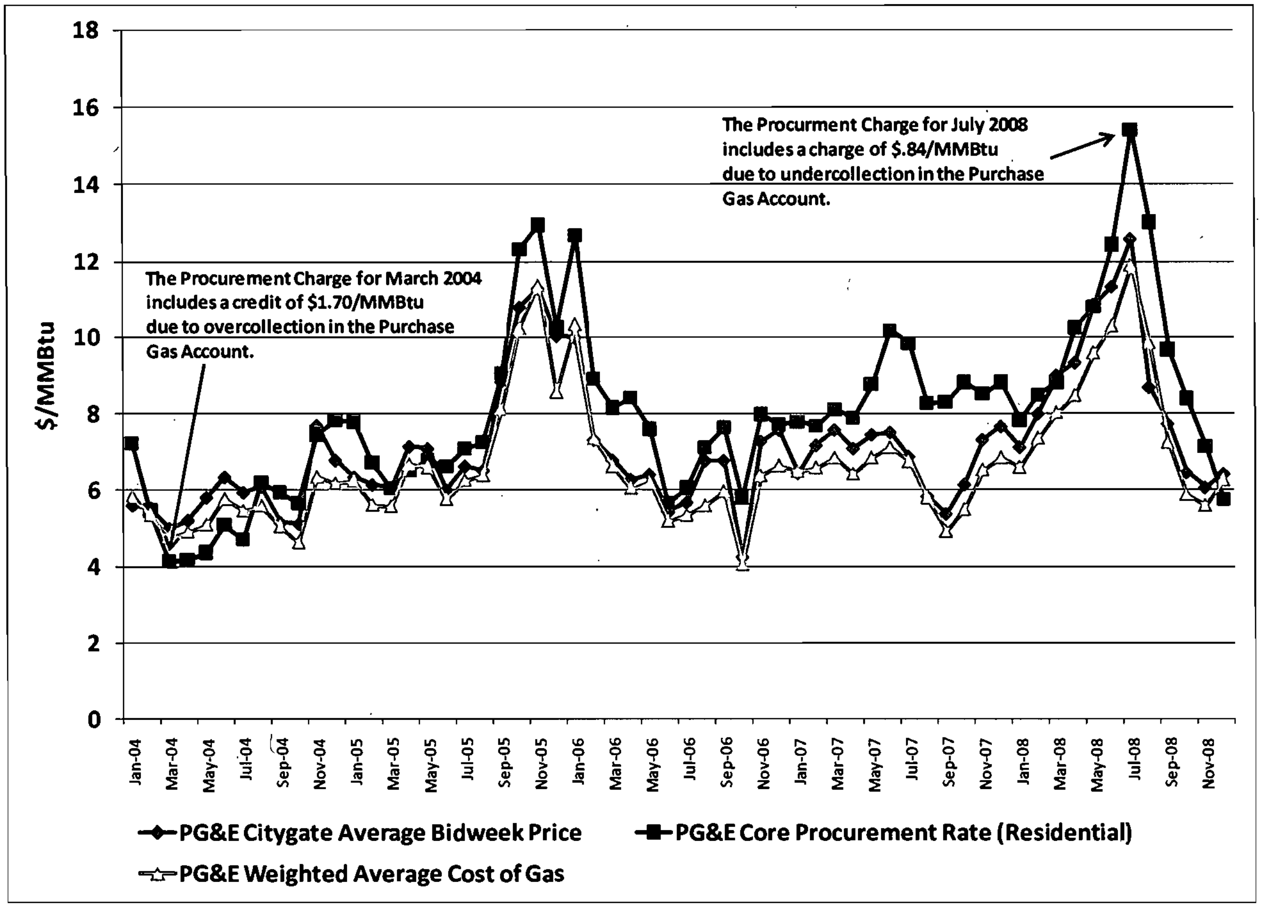
Figure 9 shows PG&E procurement charges compared to their weighted average cost of gas and PG&E Citygate bidweek prices. The data shows that PG&E's procurement charge diverges from their weighted average cost of gas and the PG&E Citygate average bidweek price in some months, but it still largely tracks the index with a similar shape and volatility. PG&E's advice letters provide details of their procurement charge. For example, PG&E's procurement charge for July 2008 was $15.409/MMBtu while their weighted average cost of gas was $11.886/MMBtu. Advice Letter 2933 for July 2008 shows the following components for their procurement charge:

PG&E Advice Letter 2933

July 2008 Procurement Charge	$/MMBtu
Winter Gas Savings Program	0.338
Winter Hedging	0.000
Core Brokerage Fee	0.032
Core Firm Storage	0.338
Shrinkage	0.529
Capacity Charge	1.285
Core Procurement Charge*	12.886
Total Procurement Charge	15.409

*The core procurement charge includes the gas supply portfolio cost, the component that amortizes the balance in the core subaccount of the purchased gas account (PGA), carrying cost on cycled storage gas, and the allowance for franchise fees and uncollectibles.

Figure 9: PG&E Price Comparison ($/MMBtu)



Source: NGI and PG&E website, www.PGE.com

Figure 10 shows SoCalGas procurement charges compared to the SoCalBorderAvg bidweek price. The data shows that the SoCalGas procurement charge tracks the SoCalBorderAvg average bidweek price. There does not appear to be much difference between the SoCalGas procurement charge and SoCalBorderAvg average bidweek price. The data is highly correlated with a correlation coefficient of 0.98 for the past two years of data.

The data shows that PG&E's procurement charge diverges somewhat from the index price while the SoCalGas procurement charge largely tracks the index, but the reasons for this result are not clear.[13] The procurement charge is an estimate, so the further the estimate is from actual costs, the more true-up of costs will be required. A closer look at PG&E's advice letters for March 2004 and July 2008 (arbitrarily selected months for demonstrative

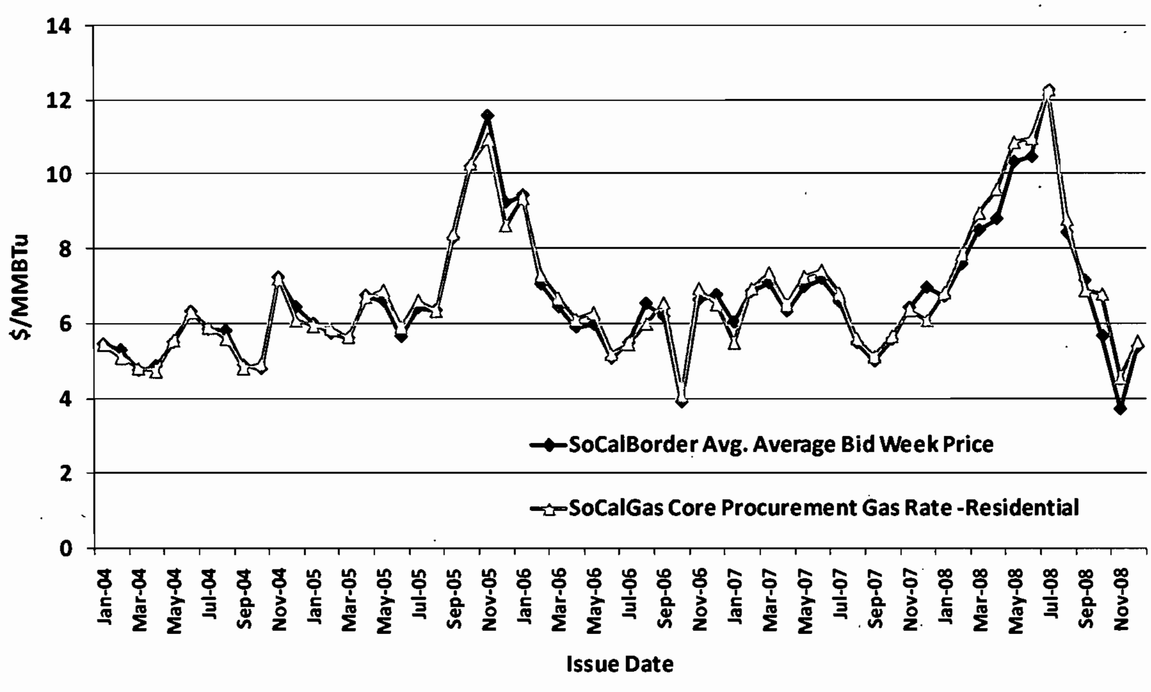
[13]PG&E acknowledges that there are significant differences between the utilities asset mix, operating conditions, incentive mechanisms, and their respective utility pipeline rules and tariffs, all of which lead to differences in procurement practices.

purposes) show that true-up of costs accounted for the largest component of the difference between the procurement charge and the index price. SoCalGas may be more successful at estimating its procurement charge, or its imbalance band adjustment provides a cushion for its estimates. SoCalGas makes adjustments to its core purchase gas account only when the over or under collection of gas costs through rates exceed a band of ±1 percent of the actual annual commodity gas purchases for the preceding 12-month period ending March 31.

Some of the other possible reasons are:

- SoCalGas has fewer procurement fees, such as no winter gas savings program.
- SoCalGas has smaller fees; maybe they pay less for pipeline capacity charges.
- SoCalGas has lower hedging costs, possibly due to lower winter demand in Southern California.
- SoCalGas system is more flexible with larger storage capacity to capture arbitrage opportunities.

Figure 10: SoCalGas Price Comparison ($/MMBtu)



Note 1: Monthly bidweek data includes transactions done at the end of each month for gas to be delivered for the entire following month.
Note 2: The residential core procurement gas price is comprised of the weighted average cost of gas including reservation charges for interstate pipeline capacity charges and carrying costs of storage, franchise fees and uncollectibles, brokerage fees, balancing account charges, and adjustment for the gas cost incentive mechanism (GCIM) reward/penalty.

Source: NGI and SCE website, www.SCE.com.

Issues

Reintegration of Hedging Within the Utilities' Incentive Mechanisms Rulemaking

Currently, there is an open proceeding at the CPUC, Rulemaking 08-06-025, issued June 26, 2008, to determine whether the utilities natural gas hedging plans can and/or should be incorporated into their existing gas cost incentive mechanisms or whether other means should be devised so that the utilities have the proper incentives to manage hedging in the best interests of core customers. A workshop was held November 5, 2008, and on January 15, 2009, the CPUC requested additional information.[14] The CPUC expects to issue a decision within 18 months.[15]

The utilities generally oppose reintegrating the cost of winter hedging back into their incentive mechanisms, while Shell Energy and DRA support including the hedging plans within their incentive mechanisms. TURN prefers the current mechanism of excluding hedging costs from the incentive mechanisms. The utilities' main argument is that the gains and losses from hedging are primarily due to factors beyond their control (for example, market fluctuations resulting from weather, macroeconomic trends, and so forth) and not a reflection of the utility's acumen. The utilities assert that incentive mechanisms are based on an area over which the utilities can exert some control – its assets; whereas, hedging strategies are attempting to minimize market price volatility – an area outside a utility's control.[16]

The main argument for reintegrating hedging costs back into the incentive mechanisms is that without them, the utilities have no financial consequences for their hedging programs. This argument is true since the hedging costs are a pass through to the utilities' core ratepayers. There is virtually no risk to the utilities because the hedging programs of the utilities are pre-approved by the CPUC and therefore, the only risk to the utilities is when they exceed the approved hedging plan costs. DRA argues that since the utilities have

---

[14] Additional comments were solicited on: 1) Risk Tolerance Issues Applicable to Southern California Customers; 2) Optional Customer Tariffs Based on Varying Risk Tolerance; 3) Performance Benchmarks for Use as Hedging Incentive Measures; 4) Treatment of Hedging: Part-Within-Versus-Part-Outside Incentive Mechanisms; 5) Possible Alternative Design of Incentive Risk Sharing Measures.

[15] In PG&E's opening comments, they suggested that the proceeding be completed within 18 months. Richard Meyers of the CPUC estimated that a decision may be made late in 2009, which would be about 18 months from the opening of the proceeding on June 26, 2008.

[16] *Final Report on Hedging Workshop*, Belinda Gatti, Rulemaking 08-06-025 (Filed June 26, 2008), November 2008.

virtually no financial exposure, ratepayers have no assurances that utilities are hedging intelligently and responsibly.

The utilities have argued that they should not be at risk for the profit/loss of a hedging program designed as price insurance. They have indicated that if the cost of hedging is reintegrated into the incentive mechanisms, they would not hedge because of the risk to their shareholders. The value of hedging needs to be weighed against the associated costs of hedging.

Hedging Workshop, November 5, 2008

At the November 5, 2008 workshop, Shell Energy presented charts comparing the utilities procurement charges to their incentive mechanisms. **Figure 11** shows PG&E's procurement charge compared to their CPIM, and **Figure 12** shows the SoCalGas procurement charge compared to their GCIM. The gas procurement charge represents the gas commodity charge that includes the weighted average cost of gas and other procurement related fees. Shell Energy stated that PG&E's and the SoCalGas existing core portfolios mirror and pass through market prices and market price volatility to core procurement customers.[17]

The incentive mechanisms are a complex calculation, but the benchmarks are largely based on monthly indices and some daily indices for PG&E, representative of where the utilities buy natural gas. The data presented in **Figure 11** showing PG&E's procurement charge compared to the CPIM benchmark is similar to the data presented in **Figure 9** showing PG&E's procurement charge compared to PG&E Citygate index. **Figure 9** is more simplified in that it compares the procurement charge to a single index. PG&E Citygate index can be viewed as a proxy for the benchmark. **Figure 11** shows that PG&E's procurement charge diverges from the benchmark cost in some months, but still largely tracks their benchmark cost.

The data presented in **Figure 12** shows that the SoCalGas procurement charge compared to the GCIM benchmark is similar to the data presented in **Figure 10** showing the SoCalGas procurement charge compared to SoCalBorderAvg Average Bidweek price. **Figure 10** is more simplified in that it compares the procurement charge to a single index. SoCalBorderAvg Average Bidweek price can be viewed as a proxy for the benchmark. **Figure 12** shows that the SoCalGas procurement charge tracks the benchmark cost with not much difference between the two.

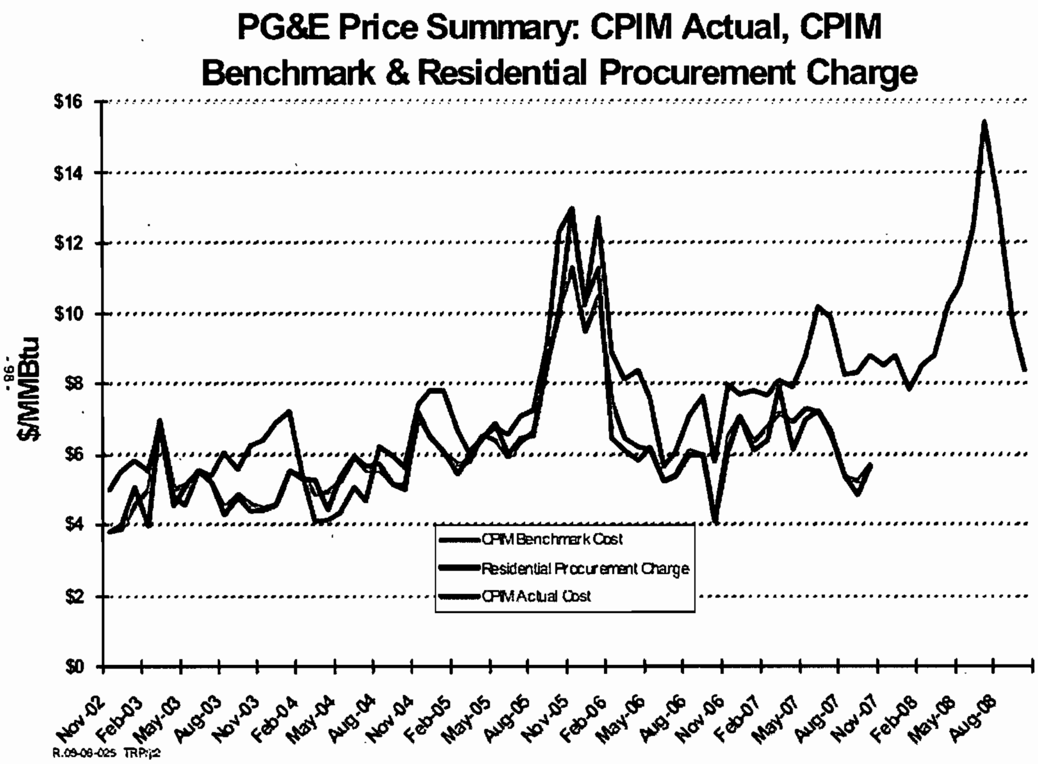
---

[17]PG&E was asked whether they agree with this assertion, and Scott Muranishi of PG&E's gas procurement group responded, "PG&E agrees that its existing core portfolio mirrors and passes through market prices and market price volatility to core procurement customers." Though PG&E agrees with this one assertion of Shell, they disagree with most other aspects of Shell's presentation.

At the workshop, the utilities total hedging costs were disclosed. DRA publishes annual reports on the incentive mechanisms and hedging costs. About $200 million have been spent on hedging during a two-year time span, winters of 2005-2006 and 2006-2007. The breakdown by utility:

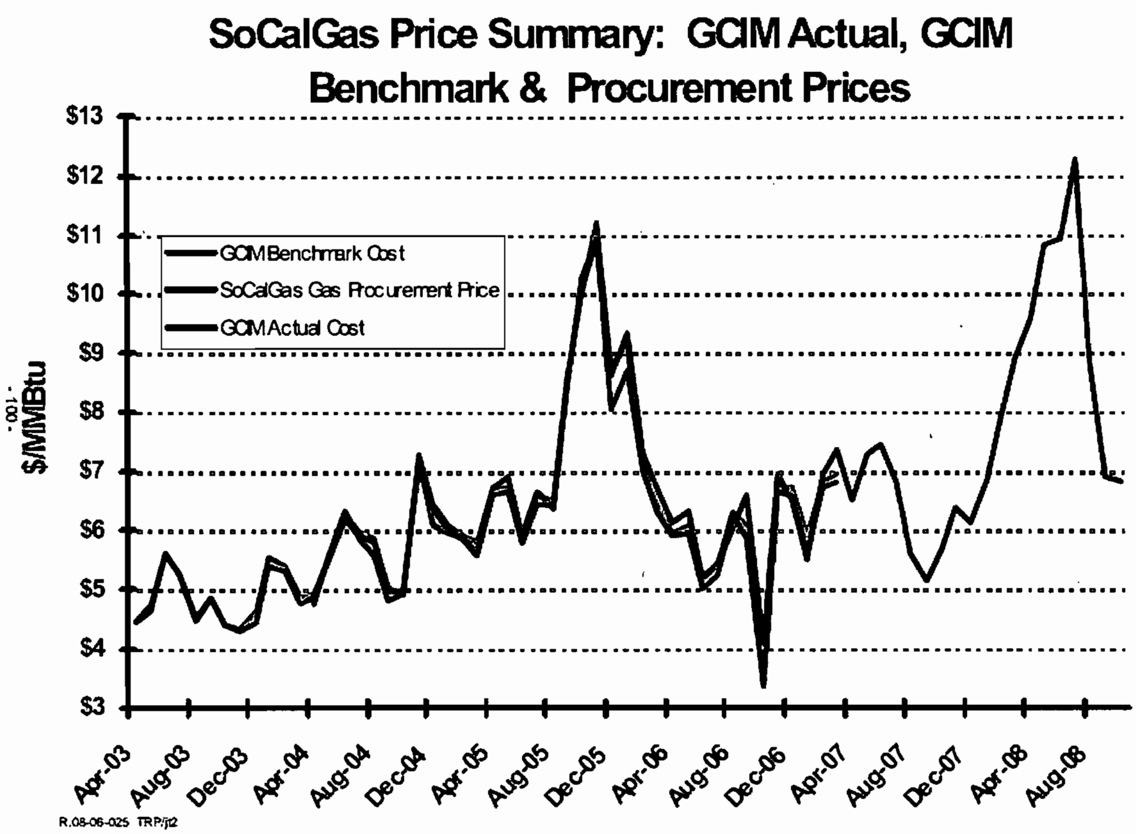
- PG&E has spent more than $134 million.
- SoCalGas has spent just over $46 million.
- SDG&E has spent more than $29 million.

Figure 11: PG&E Price Summary



Source: Shell Energy

Figure 12: SoCalGas Price Summary



Source: Shell Energy

PG&E has spent three times as much as SoCalGas and has fewer customers, estimated at 4.2 million compared to 5.1 million customers. One reason that PG&E may have spent more is that its winter demand may be higher than SoCalGas. These two utilities have different philosophies about hedging. PG&E takes a more systematic approach to hedging by executing transactions relatively evenly over time to diversify timing risk. PG&E does not take a view on the market, while SoCalGas stated that its hedging program is a little more dynamic, basing their hedging activity on their analysis of the market. Shell stated that PG&E's programmatic approach has led to excessive hedging costs because PG&E is not accountable for its hedge costs. Shell cited PG&E's hedging plan as excessive and disputed the tangible benefits of PG&E's current hedging plan.

Since the hedging costs are passed on to ratepayers, the core procurement charge contains the impact of hedging. Hedging costs may partially explain some of the differences between PG&E's procurement charge and WACOG, but certainly not all of the differences. A sample look at two months of advice letters shows that most of the difference is based on a true-up of costs. An example of PG&E procurement charge details for July 2008 was shown previously in the section "Cost Recovery and Procurement Charge." Winter hedging costs were $0 in July, so there are other procurement related charges making up the difference, such as balancing account charges. In winter months, the hedging costs can be a significant amount of the procurement charge. For example, in December 2008, the hedging costs are about $1.02/MMBtu of the procurement charge of about $5.74/MMBtu. Hedging costs are almost 18 percent of the procurement charge.

Customer Risk Tolerance Survey

Financial hedges are a form of price insurance used to protect customers from excessively high and volatile natural gas price swings. There is a cost associated with hedging. How does one balance the risks associated with hedging and the benefits of hedging? PG&E believes that different customers may have different risk tolerance levels. It is currently conducting a survey of its customers to determine risk tolerance levels. It believes that those customers with a higher risk tolerance may require less hedging than those with a lower risk tolerance level. Its survey intends to determine the risk tolerance of their customer base, and this information may impact their hedging strategies in the future. The results of the customer risk tolerance survey will be included in the CPUC proceeding, Rulemaking 08-06-025.

Summary

The CPUC and DRA indicate that the utilities tend to procure natural gas under short-term monthly contracts. The gas cost incentive mechanisms established by the CPUC encourage utilities to procure natural gas at or below a benchmark price. The benchmark price is based on a basket of monthly and some daily indices. They will also share in the savings with ratepayers if the cost-to-benchmark differences are below a certain threshold (the deadband around the benchmark), or will be penalized if their costs are above a certain threshold. PG&E's weighted average cost of gas tracks the PG&E Citygate average bidweek price. SoCalGas' weighted average cost of gas is not publicly available, but staff has determined that their procurement charge tracks the SoCalBorderAvg average bidweek price. The data suggests that the utilities are buying gas for their core customers priced at the monthly index. These findings show that ratepayers are not immune to the natural gas prices or volatility in the marketplace, but the gas utilities do employ limited hedges to protect ratepayers from natural gas price spikes during the winter.

Sources

Augustine, Broxson, Peterson (2006). *Understanding Natural Gas Markets.*

California Gas and Electric Utilities (2008). *2008 California Gas Report.*

California Public Utilities Commission (2001). *California Natural Gas Infrastructure Outlook 2002-2006.*

California Public Utilities Commission (2008). *R.08-06-025, Order Instituting Rulemaking to Address the Gas Utilities' Incentive Mechanisms and the Treatment of Hedging Under Those Incentive Mechanisms.*

Division of Ratepayer Advocates (2005). *Monitoring and Evaluation Report November 1, 2005 through October 31, 2005 on Pacific Gas and Electric Company's Core Procurement Incentive Mechanism(CPIM Year 12)Performance Results.*

Division of Ratepayer Advocates (2008). D.07-11-001, *Comments of the Division of Ratepayer Advocates, January 24, 2008.*

Gatti, Belinda, Energy Division, California Public Utilities Commision, (2008). *R.08-06-025, Final Report on Hedging Workshop,* November 2008

Peevey, Michael R. (2005). Comments of Michael R. *Peevey before FERC October 20, 2005 California's Response to Natural Gas Prices Winter 2005-06.*

Southern California Gas Company (2008). *Application of Southern California Gas Company (U 904 G) Regarding Year 14 (2007-2008) of its Gas Cost Incentive Mechanism.*

State of California Energy Commission and Public Utilities Commission (2006). *Natural Gas Market Study, Prepared for The Honorable Senator Escutia, Chairwoman*

Strauss, Todd (2008). *Hedging and Price Risk Management: A California Perspective*