COM/GMW/rmn

Mailed

MAR 1 4 1991

Decision 91-03-032 March 13, 1991

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking on the Commission's own motion to change the structure of gas utilities' procurement practices and to propose refinements to the regulatory framework for gas utilities.	R.90-02-008 (Filed February 7, 1990)
Investigation on the Commission's own motion into the effectiveness of incentive mechanisms to reduce electric utility costs.	I.90-08-006 (Filed August 8, 1990)

OPINION

This decision spins off into I.90-08-006 our investigation into gas utility incentives, which has been part of the rulemaking on procurement practices. We rendered our decision on noncore gas procurement and transportation rules in September 1990 (Decision (D.) 90-09-089). This decision addresses incentives for keeping down the costs of gas utility core gas and other utility expenses ("nongas costs").

I. Summary

After reviewing the second set of responses to our questions about the advantages and disadvantages of new incentive approaches to nongas costs and core gas procurement costs, we continue to believe that an indexing approach to nongas cost regulation could provide substantial benefits in increased efficiency, innovation, ratepayer protection, risk allocation, and regulatory simplicity. The further exploration of indexing nongas costs for gas utilities should be removed from R.90-02-008 and joined with our exploration of incentives for electric utilities, because the combined gas and electric utilities should not be faced with different regulatory frameworks for their gas and electric utility operations. In order to create an evidentiary record on the merits of a broad range of ratemaking incentives, we intend to order the respondents in the spunoff portion of this proceeding and the electric proceeding to submit testimony on indexing and other approaches to regulating nonfuel costs. Intending that our gas industry deliberations not prejudice treatment of electric utility incentives, we will consolidate only the investigation of gas utility incentives in this rulemaking with our investigation on incentive mechanisms to reduce electric utility costs, Investigation (I.) 90-08-006. The gas utility incentive issues will then become a part of I.90-08-006 and no longer be included in the docket for R.90-02-008. Our preliminary thinking is that ratemaking incentives in the gas and electric industries should be consistent, so we will defer filing of gas incentive testimony until the first round of comments is filed in I.90-08-006.

With respect to core procurement, the parties have persuaded us that the difficulties of implementing either a price index or a multiple-goal performance report card approach outweigh the benefits at this time. We will continue 100% balancing account treatment for these costs with reasonableness reviews. The consolidated proceeding will eventually consider whether to split fuel-related costs, both gas and electric, into balancing account and indexed or forecast portions. We will undertake this review in the context of careful assessment of overall risks and rewards for energy utilities. We will also consider whether testimony should be submitted on indexing purchased fuel costs once the proceedings are consolidated under I.90-08-006. A decision or ruling will be issued at the appropriate time to notify the parties of this intention.

II. Background

On February 7, 1990, we issued R.90-02-008 which proposed general changes to the Commission's framework for gas utility regulation. The focus of the rulemaking was on noncore gas procurement changes. D.90-09-089 set forth the new rules for utility noncore gas procurement and transportation services. As part of the rulemaking, we asked parties to explore new incentive mechanisms to promote efficiency in nongas costs and core gas procurement. We analyzed the parties' responses in D.90-07-065 issued July 19, 1990. In that decision we repeated our commitment to further exploration of indexing approaches and asked parties to respond to specific questions, including questions about the design of new indexing mechanisms. This decision analyzes those responses and sets the future procedural path.

III. Positions of the Parties

A. Southern California Gas Company (SoCalGas)

Generally, SoCalGas argues that no changes to existing mechanisms should be adopted without compelling reasons for doing so and opposes changes at this time. It does not believe incentives in addition to those already in place are likely to improve upon the efficiencies achieved in the competitive gas procurement market.

SoCalGas proposes an alternative framework if the Commission decides to go forward with indexing of gas costs.

B. Pacific Gas and Electric Company (PG&E)

Like SoCalGas, PG&E believes the existing reasonableness reviews are adequate for assuring low cost gas purchasing strategies, but proposes an alternative mechanism in case the Commission decides to adopt an indexing approach. PG&E also recommends performance criteria beyond price, including reliability and WMBE participation.

PG&E opposes nongas cost indexing and argues it should not be considered in isolation from ratemaking policies for electric utilities.

C. San Diego Gas and Electric Company (SDG&E)

SDG&E believes regulatory incentives, with opportunities for reward as well as penalties, are useful if they are well-structured. It argues, however, that the mechanisms put forth in D.90-09-089 offer no advantages over the existing system.

SDG&E accepts the idea of an indexed gas cost (IGC) mechanism if the utilities' risk for forecasts is removed and the Supply Adjustment Mechanism (SAM) is reinstated. It proposes hearings be held for determining any new regulatory program and comments that the Commission should allow the regulatory changes recently ordered in the gas industry be allowed to evolve before pursuing any new ratemaking incentives.

D. Division of Ratepayer Advocates (DRA)

DRA believes that indexing of both core gas costs and nongas costs may improve the incentives for utility cost containment. DRA proposes a conceptual approach to indexing core gas costs but recommends hearings and more detailed consideration of the issue. On the subject of nongas costs, DRA proposes that this rulemaking be consolidated with the investigation on electric incentives to assure compatability between gas and electric incentives which DRA believes is especially crucial for utilities which provide both gas and electric services.

E. Toward Utility Rate Normalization (TURN)

TURN strongly opposes indexing nongas costs before there is any evidence that this approach has been successful in the telecommunications arena. It offers its "cautious" support for partial gas cost indexing but states that its support is premised on the assumption that reasonableness reviews would be retained.

F. Canadian Producer Group (CPG)

CPG believes the implementation problems associated with indexing core gas costs are "insurmountable." It also opposes the Commission's proposal to index nongas costs and is especially concerned over how the Commission can create an incentive for efficiency without reference to the use made of the utility's system in terms of throughput.

G. California Industrial Group (CIG)

CIG opposes the indexing of nongas costs and core gas costs, arguing that the Commission has not demonstrated a need for indexing and that utility customers are unlikely to benefit from the changes the Commission proposes.

H. California Gas Producers Association (CGPA)

CGPA also opposes indexing of gas costs, believing that other incentives may better promote market competition. CGPA argues that indexing nongas costs may promote efficiency and recommends hearings on the subject.

IV. Nongas Costs--Incentive Approaches

The nongas costs of the gas utilities, including wages and benefits, operating and administrative costs, and construction costs are substantially under the control of utility managements. We have noted in our decision adopting a new regulatory framework for Pacific Bell and GTE California, Inc. (GTEC) that replacing traditional cost of service regulation with an indexing approach can challenge utility managements to become more efficient while protecting monopoly ratepayers (D.89-10-031). Our experience through two annual indexed rate changes for those companies indicates the approach can work simply and quickly, with ratepayers receiving an automatic productivity dividend without a lengthy and costly rate case.

Therefore, despite the objections of nearly all the parties in this proceeding, we are committed to carefully scrutinizing a similar approach for nongas costs. After the consolidation, we will direct the Division of Ratepayer Advocates (DRA) and the gas utilities to submit detailed proposals for improving the way we regulate nongas costs.

The responses have shown us two factors that make gas utilities different from telecommunications utilities. One is the wide fluctuation in gas sales caused by the weather. We cannot index base rates for gas utilities because they could over- or under-recover their revenue requirement due to the weather. Therefore, as we noted in D.90-07-065, the appropriate approach would be to index the nongas revenue requirement while retaining a revenue requirement balancing account.

The second difference, which needs further explanation, is the situation related to rate base additions for customer growth. PG&E and SoCalGas point out that they do not recover the costs of adding new customers in the installation fees and sales revenues, and, therefore, a separate treatment may be needed for small rate base additions. We do not view this as an insurmountable problem, and, as PG&E points out, a separate index that includes housing growth may be appropriate for that cost category.

The responses indicate to us that either one index or a series of indices tailored to separate major cost categories may be appropriate. SoCalGas notes that the Consumer Price Index for the Los Angeles and Anaheim area has tracked its nongas costs. Other parties mention possible indices including the Handy Whitman construction index of gas industry costs or the U.S. Bureau of Labor Statistics index of total factor productivity in the private nonfarm sector. We look to the parties to provide analysis on the advantages and disadvantages of applying these and other general inflation-related indices. For the telecommunications utilities, we adopted the national Producers Price Index.

The gas utility responses argue that no one index is appropriate for their nongas costs. PG&E presents an illustration involving multiple-cost categories and indices. They apply a Data Resources International composite of 17 materials and services cost indices to their cost of materials, the Bureau of Labor Statistics wage index to labor costs, and a straight 9.5% a year rate to apply to health costs. For the small rate base additions associated with customer growth, the illustration applies a composite of the labor and the materials index plus a growth index tied to housing starts.

The advantages of multiple-cost categories and indices is that they can mimic underlying changes in costs more closely than a more general index. The disadvantages are that they are more complicated, and the more specific they are, the more they can resemble a low-risk balancing account and the more easily a utility could tie labor and materials contracts to the indices. There are other advantages and disadvantages of these two index approaches we would like explored in the testimony once it is directed to be filed.

The utilities also present a list of costs they believe should either continue to receive separate Commission approval of authorized revenue requirements, or simply automatic pass-through to rates. Suggested pass-throughs include Federal Energy Regulatory Commission pipeline demand charges, costs of lost and unaccounted for gas, interutility charges, postage, taxes, franchise fees, all government mandated costs, the CPUC fee, demand side management program costs, Research Development & Demonstration (RD&D) costs, and even interest costs. Suggested candidates for separate traditional cost of service treatment include future tax liabilities, balancing benefits already flowed through to ratepayers, major capital additions, taxes, Demand Side Management, and RD&D program costs.

It is certainly appropriate to consider these cost categories for exemption from indexing treatment, but we are interested in keeping them to a minimum. The greater the exemptions, the more a new framework resembles guaranteed return ratemaking. We wish to make it clear that just because utility management has limited control over a cost category, that does not mean such a cost automatically should receive cost-plus regulation. The risk of cost changes is a normal risk of conducting any business, and the Commission-authorized rates of return compensate shareholders for such risks. With the telecommunications utilities' new framework, we authorized changing rates, up or down, to compensate for major cost changes clearly out of the utilities' control, with tax changes serving as a clear example. These changes are adopted in separate proceedings and are then consolidated in the annual rate indexing advice letter filing.

On other elements of a possible new regulatory framework, the responses were limited. PG&E's illustration includes the Commission annually adjusting the cost of debt and equity and the capital structure. For the telecommunications utilities, utility management determines the capital structure and the Commission does not reset the costs of capital. Instead there are financial triggers and safety nets, which include sharing of returns with ratepayers when return on rate base exceeds 13%, a re-evaluation if Treasury bill rates change by more than 3%, and a re-evaluation if a floor return of 8% is pierced for two years. PG&E and DRA state they would favor a rate of return band for the gas utilities that would involve sharing when the band is exceeded.

On the subject of productivity, any index incorporates some level of productivity. A national producers price index subsumes a national level of productivity. For the telecommunications utilities, we adopted a 4.5% productivity adjustment to the index. The gas utilities state that they have no technological innovations that can help make them more efficient and that their productivity levels have been zero or even negative. However, in their general rates cases we have seen overall productivity improvements, and Great Britain adopted a 2% productivity adjustment from the national consumer price index for their gas utility, effective for a five-year period. So we look forward to testimony on future productivity levels the gas utilities could or should be expected to achieve.

We take seriously the opposition by all the parties except DRA to changing the current regulatory system, which consists of general rate cases every three years with operational and financial attrition proceedings in the other two years. Unlike Pacific Bell and GTEC, the gas utilities have not been complaining about detailed cost of service regulation. The parties seem to be comfortable with the traditional approach. After hearings and recommendations we may still decide not to change the rate case and attrition framework. But after two rounds of responses in this proceeding, we have not seen any compelling reason to shrink from a serious attempt at replacing the lengthy and detailed cost of service approach with index-based incentive ratemaking for nongas costs. We are not interested in preserving the status quo because it is comfortable. We are looking for ways to energize utility management to actively pursue efficiency improvements and innovation, with opportunities to exceed what would be Commission-authorized rates of return, while protecting the ratepayers and giving them timely and predictable productivity dividends.

V. Core Gas Procurement Costs Incentives

We have also been exploring in this proceeding, ways to provide more balanced incentives for the gas utilities to minimize their costs of procuring gas for core customers. Our regulatory framework has been to provide a 100% balancing account treatment, with a review of the reasonableness of the utilities core gas purchases conducted after the purchases were made, and with the possibility of a disallowance of costs that the Commission finds unreasonable. We hope to discover an approach that could eliminate or lessen the need for after the fact reasonableness reviews, and that could provide the utilities with balanced financial incentives to make efficient purchases and minimize costs to ratepayers. Unfortunately, two rounds of comments in this proceeding have not yet provided us with a method for replacing balancing accounts and reasonableness reviews in which we have the confidence to implement at this time, and it may not be feasible to do at all.

After the first round of responses, we rejected the approach of an annual gas rate similar to the Annual Energy Rate (AER) applied to the fuel and purchased power costs of the electric utilities. We found that such a short-run incentive provided no long-term incentive for prudent gas purchase contracts because the annual revisions would take away any savings the utilities manage to obtain through contracts. On the other hand, extending a forecasted rate covering natural gas costs to two years or more presents the likelihood the forecast will be substantially wrong, especially since weather has such a major effect on gas prices.

Our choice against forecast ratemaking for a fraction of fuel-related expenses is not final. In future hearings we intend to review short-term and long-term purchasing incentives, in light of actual utility portfolios. As well, we do not wish to prejudice electric utility policy choices by the permanent abandonment of forecast treatment of fuel-related costs.

We asked parties to address the desirability of a long-term index to be applied to a small portion of core gas costs. Parties mentioned a wide variety of candidate indices, including a market basket of regional gas prices (SDG&E), the gas futures prices at the Henry Hub in Louisiana (PG&E), utility specific California-Arizona border prices (SoCalGas), weighted mainline or border prices (DRA), and a national index to include spot and long-term contract markets (TURN).

But the parties point out that adoption of an index applied to part of core gas costs could present a number of disadvantages. It could be a disincentive to core service reliability, because gas prices peak in cold weather when the core needs gas the most. The utilities would have a financial incentive to avoid gas supplies that cost more, or whose prices change more, than the selected index. Adoption of a price index could also be manipulated by the utilities. They could tie the gas prices in their contracts to the index and thereby avoid risk. We also note that a gas price index is very difficult to select. If the index represents the prices of supply sources purchased by a specific utility, then it really mimics a balancing account because those prices are under the control of the utility. If the index is a broad national or regional one, it then presents the likelihood it could be far off from the actual prices obtained by the utility through no fault of utility management.

We believe that the parties have not fully developed the idea of using indexes. We believe a properly constructed index would track relative price movements and not be dependent upon price levels in specific markets. It may be likely that most, if not all, indexes would closely track each other. On an annual basis we might expect natural gas prices to rise in winter and fall in spring in all gas markets. This should lead to a high degree of conformity between indexes. When we revisit the question of indexing purchased gas costs we will entertain showings directed at the question of whether indexes can be constructed that are not systematically biased.

The utilities have also argued that gas purchase prices are beyond the control of utility management. This result usually occurs in markets where utilities are small purchasers relative to the market. If such is the case we must also dismiss utility arguments that they are able to receive better prices for their customers because of vertical integration and aggregation of purchases between customer classes. Since we have not yet received testimony on these points, we will defer such consideration until testimony is filed on purchased gas cost indexing.

The utilities state that in place of a price index they would prefer a framework of rewards or penalties based on their performance with respect to pre-established measures. These measures would include measures of both reliability and price, and of other Commission goals such as women and minority business participation, avoidance of large price swings, and possibly the treatment of in-state gas production. This framework would be like a report card, as preferred by PG&E, SoCalGas, and DRA.

PG&E provides an illustration of how this might work. Reliability would be weighted 75%, and 100% core service would award them 100 points. PG&E would lose a point for every 0.1% cut in service, so it would receive 50 points if service were 95%. Gas cost changes would be weighted 25%. If PG&E's cost of core gas rises twice as much as the Hub gas price rises, it is awarded no points. If the price changes are equal, it receives 50 points. If PG&E's price rises 100% less, or half as much, as the Hub price, it receives 100 points. With 200 points, PG&E would receive a reward of $10 million from ratepayers, while no points would result in a penalty of $10 million. SoCalGas' illustration would risk $13 million, with this report card approach replacing reasonableness reviews. PG&E's illustration would give the report card a two-year period, to be verified by an independent auditor. The utilities then contemplate that they would continue to receive 100% balancing account treatment for their core gas costs. The report card approach, with its possible reward or penalty, would supplant reasonableness reviews. TURN insists on continuation of reasonableness reviews, no matter what changes might be adopted.

We certainly agree with the utilities that we are concerned about reliability of service to the core. In fact, the Commission is heavily involved in assuring 100% core service through our ability, under emergency conditions, to allow the utilities to divert noncore transportation customers' gas to serve the core. So it is difficult to foresee how prudent utility management could ever lose points for core curtailments. Moreover, our first obligation is to assure service to core customers who have no reasonable alternatives to gas service.

After reviewing these responses, we are persuaded that we do not want to create any incentives that could undermine reliability; we do not want to create a report card system tilted in the utilities' favor; and we do not want to pre-establish performance measures that could distract utility managements from providing reliable core service at the lowest reasonable cost. However, we hesitate to accept assertions that utility management would place profits ahead of assured core service. We note that irregular and temporary price rises of a few days duration should have a small impact upon any properly constructed index based upon an entire year of operations. Such effects would only be significant if unusually warm or cold weather occurred only in localized markets without having regional or national effects. We also note that with the newly competitive gas markets there is much more pricing and bidding information available with which to assess the reasonableness of utility purchases. With utilities using bidding procedures for obtaining spot and long-term contract gas supplies it may be relatively easy to be a prudent gas purchaser. With the current record it is not clear that added benefits could be obtained by an indexing or report card approach. Therefore, we continue 100% balancing account treatment of core gas purchases, and may ask for testimony on these issues at the appropriate time.

We will also continue with reasonableness reviews. While these can be difficult and contentious at times, we note that the controversial ones can involve important tradeoffs between price and reliability. We expect utility managements to be experienced, sophisticated, flexible, and well-informed practitioners of that tradeoff, and we will continue to be the overseers on behalf of the core ratepayers of such management decisions. While reasonableness reviews can only result in utility shareholder losses, and never a gain, we note that the utilities' risks are otherwise nonexistent due to the 100% balancing account cost recovery they obtain for all core gas purchases. The reasonableness reviews are the price they pay for this substantial financial protection.

Findings of Fact

1. Consolidation of the issue of indexing gas and nongas costs for gas utilities, now in R.90-02-008, with I.90-08-006 will allow consideration of the same regulatory framework for the gas and electric utility operations of combination gas and electric utilities.

2. An indexing approach to nongas cost regulation could provide substantial benefits in increased efficiency, innovation, ratepayer protection, risk allocation, and regulatory simplicity.

3. Deferring the filing of gas incentive testimony until the first round of comments is filed in I.90-08-006 will provide an opportunity to promote consistency in ratemaking incentives for the gas and electric industries.

Conclusions of Law

1. The further exploration of indexing gas and nongas costs for gas utilities, now in R.90-02-008, should be spun off from R.90-02-008 and joined with the Commission's investigation of incentives for electric utilities (I.90-08-006). The gas utility incentive issues should become part of I.90-08-006 and should no longer be included in the docket for R.90-02-008.

2. After this consolidation, the I.90-08-006 proceedings should consider a split of fuel-related costs, both gas and electric, into balancing account and indexed or forecast portions.

3. Testimony on gas utility incentives should be deferred until a ruling or decision in I.90-08-006, or other appropriate proceeding.

ORDER

IT IS ORDERED that:

1. The exploration of indexing gas and nongas costs for gas utilities now in Rulemaking (R.) 90-02-008 is transferred to Order Instituting Investigation (I.) 90-08-006, the investigation into the effectiveness of incentive mechanisms to reduce electric utility costs for the purpose of considering further incentives to promote efficiency in managing gas utility costs.

2. After this transfer, the I.90-08-006 proceedings will address a possible split of gas and electric fuel-related costs into balancing account and indexed of forecast portions.

3. Testimony on gas utility incentives is deferred until a further order or ruling in I.90-08-006.

This order is effective today.

Dated March 13, 1991, at San Francisco, California.

PATRICIA M. ECKERT
President
G. MITCHELL WILK
JOHN B. OHANIAN
DANIEL WM. FESSLER
Commissioners

I abstain.

NORMAN D. SHUMWAY
Commissioner

I CERTIFY THAT THIS DECISION WAS APPROVED BY THE ABOVE COMMISSIONERS TODAY

Neal J. Shulman

NEAL J. SHULMAN, Executive Director

po