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Review of Performance-Based Ratemaking Plans for U.S. Gas Distribution Companies

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DISCLAIMER

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Acronyms and Abbreviations

BLS	U.S. Bureau of Labor Statistics
BUG	Brooklyn Union Gas Co.
CERA	Cambridge Energy Research Associates Inc.
COS/ROR	Cost of Service/Rate of Return
CPCN	Certificate of Public Convenience and Necessity
CPI	Consumer Price Index
CPI-U	Consumer Price Index, Urban Consumers
DSM	Demand side management
ECI	External cost index
EIA	Energy Information Administration, U.S. Department of Energy
FERC	Federal Energy Regulatory Commission
GCIM	Gas Cost Incentive Mechanism
GCR	Gas cost recovery
GDP	Gross Domestic Product
GNPPI	Gross National Product Price Index
GPNA	Gross plant net additions
GRI	Gas Research Institute
IRP	Integrated resource planning
LDC	Local distribution company
LEC	Local exchange companies
MERIT	Measured Equity Return Incentive Term
MichCon	Michigan Consolidated Gas Co.
NJNG	New Jersey Natural Gas Co.
NMGas	Niagara Mohawk Power Corporation's Gas Department
NYMEX	New York Mercantile Exchange
O&M	Operations and maintenance
PBR	Performance Based Ratemaking
PG&E	Pacific Gas & Electric Co.
PGA	Purchased gas adjustment
PSC	Public Service Commission
PUC	Public Utility Commission
ROE	Return on equity
SDG&E	San Diego Gas & Electric Co.
SoCal	Southern California Gas Co.
UCI	Unit cost index
USR	Uniform Statistical Reports

Abstract

Performance-Based Ratemaking (PBR) is receiving increased attention by energy utilities and their regulators. PBR is the industry term for forms of regulation that increase financial incentives for performance relative to traditional cost-of-service/rate-of-return (COS/ROR) regulation. In this report, PBR plans filed by U.S. gas local distribution companies (LDCs) are described and reviewed. The rationale behind energy utility PBR is presented and discussed. Using nine plans that have been proposed by eight LDCs as a basis, a framework (typology) to facilitate understanding of gas utility PBR is presented. Plans are categorized according to the range of services covered by the PBR mechanism and the scope of the mechanism's cost coverage within a service category. Pivotal design issues are identified and, based on the sample of plans, observations are made. Design issues covered include the length of time that the PBR is in effect (term); the relationship between PBR plans and status quo ratemaking; methods for formulating cost or rate indices, earnings sharing mechanisms, and service quality indices; and compatibility with gas utility DSM programs. The report summarizes observations that may be considered supportive of the rationale behind PBR. PBR is, however, not clearly superior to traditional regulation and few PBRs that are broad in scope have been adopted long enough to allow for a empirical analysis. Thus, the report concludes by identifying and describing commonly-cited pitfalls of PBR.

1 Introduction

Performance Based Ratemaking (PBR) is used by energy utilities and their regulators to identify ratemaking mechanisms that strengthen incentives to improve rates, costs, or other aspects of performance compared to traditional Cost of Service/Rate of Return (COS/ROR) regulation. PBR mechanisms that broadly cover categories of service or costs have not been widely adopted in either the electric or natural gas industries, although there is increasing interest for it in both. This report discusses and reviews nine PBR proposals that have been adopted or proposed by eight U.S. LDCs.

PBR has its analytic roots in the area of economics known as incentive regulation. The literature on incentive regulation for public utilities, public procurement programs, and common carriers is large (Laffont and Tirole 1993). Actual experience with incentive regulation appears to be the greatest in the telecommunications and interstate rail industries (Johnson 1989; Lowry 1991). Incentive ratemaking mechanisms for electric utilities have also been adopted, although most mechanisms target performance in the areas of fuel and purchased power costs and power plant performance (Joskow 1986; Berg and Jeong 1991). In the natural gas industry, specific incentive regulation plans for interstate pipeline companies and LDCs have been proposed (Brown et al. 1989; Brown et al. 1991; Lyon and Toman 1991; Lowry et al. 1993) and price-cap regulation for gas utilities has been adopted in the U.K. for British Gas (CERA 1993). The number of U.S. LDCs that are considering PBR or are operating subject to it appears to be growing and, thus, motivates the focused examination of gas utility PBRs in this report.

Collectively, the eight utilities have proposed and filed nine separate incentive ratemaking plans (Table 1). The primary criteria for inclusion of incentive ratemaking plans in this report was scope: plans that broadly cover categories of prices, services, or costs were selected over plans that target limited aspects of LDC operations. However, targeted incentive mechanisms that are a part of a broader incentive ratemaking plan are also considered in this report as is one novel targeted incentive mechanism that involves the gas futures market. The plans are in various stages of regulatory approval. Seven plans have been adopted, one (PG&E's) is pending approval, and one (NJNG's) was withdrawn by the utility before its Commission ruled on it. NJNG's plan has been retained because its features are still instructive to utilities and public utility commissions (PUCs) that are considering incentive regulation. Of the eight utilities, five serve customers from only two states: New York and California.

In general, this report describes the plans as they were filed. For the seven adopted plans, filed and adopted plans are very similar, except for Wisconsin Gas's, which originally included a rate cap but was adopted as a rate freeze. In addition to utility-filed plans, PUC orders and intervenor testimony are used when available to describe the PBR mechanism or issues. Because many of the proposed incentive mechanisms are not yet operational, no attempt was made to collect data on utility performance under the incentive ratemaking plans.

This report first develops working definitions of traditional regulation, incentive regulation, and PBR (Section 2). The rationale for PBR is also presented. A typology of PBR is proposed in Section 3. Various types of mechanisms are briefly described to explain the typology and the report indicates which utilities have sponsored what types of plans. In Section 4, observations based on the reviewed plans are made as they relate to ten design issues. The report concludes by summarizing the observations of the report in terms of how they may support theorized benefits and pitfalls of PBR.

Table 1. Sample of Gas Distribution Company Ratemaking Incentive Plans

	Company	Utility Type: LDC or Combination	Plan Title	Term (Years)†	Regulatory Status (as of Oct. 1994)
1.	Brooklyn Union Gas Co. (BUG)	LDC-only	Multi-year rate proposal, Customer Service Quality Incentive Program, and various targeted incentive mechanisms	3	adopted October 1994
2.	Michigan Consolidated Gas Co. (MichCon)	LDC-only	Procurement risk management proposal	2	proposed in 1993, adopted in 1994, implementation is expected early 1995
3.	New Jersey Natural Gas Co. (NJNG)	LDC-only	Incentive Ratemaking Plan	4	proposed in 1993; plan withdrawn early 1994 although limited targeted throughput incentives adopted in early 1994.
4.	Niagara Mohawk Power Co. Gas Department (NMGas)	Combination	Measured Equity Return Incentive Term (MERIT) Program	3	adopted beginning of 1993
5.	Pacific Gas & Electric Co. (PG&E)	Combination	Regulatory Reform Initiative	6	proposed in 1994; case before PUC
6.	San Diego Gas & Electric Co. (SDG&E)	Combination	Performance-Based Ratemaking (PBR) Base Rate Mechanism	6	adopted August 1994
7.	San Diego Gas & Electric Co. (SDG&E)	Combination	PBR Proposal for Gas Procurement	2	adopted beginning mid-1993
8.	Southern California Gas Co. (SoCal)	LDC-only	Gas Cost Incentive Mechanism (GCIM)	3	adopted beginning mid-1994
9.	Wisconsin Gas Co.	LDC-only	Productivity-based Alternative Ratemaking Mechanism (PARM)	4	proposed in 1993; PSC adopted, mid-1994, a base-rate freeze (over an index) with no weather adjustment mechanism

† Terms for the base-rate incentive plans (BUG, NJNG, PG&E, SDG&E, and Wisconsin Gas) include the litigated base year plus the number of years subject to indexing.

2 Performance-Based Ratemaking as an Alternative to Traditional Regulation

2.1 A Definition and Simple Model of Performance-Based Ratemaking

The most common strategy employed by PBR mechanisms is to weaken the link between a utility's regulated prices and its costs. This decoupling is done either by decreasing the frequency of rate cases and/or by employing external measures of cost for the purposes of setting rates. PBR mechanisms are developed with the recognition of the information asymmetry between the regulator and the regulated utility. Thus, while it may be possible to conduct even more complex regulatory proceedings to improve utility prices,[1] costs, and performance, such methods are assumed to be infeasible (or would require excessive regulatory costs) and are not considered a type of PBR. Instead, PBR places an emphasis on ratemaking methods that improve performance *without* resorting to micromanagement.

The discipline of economics has produced a large literature on incentive regulation for public utilities. In this paper, the term *incentive regulation* is used to refer to the economics literature and *PBR* is used to refer to mechanisms that have actually been proposed for public utilities. Thus, PBR may be considered to be a subset of the ratemaking mechanisms that have been examined in the incentive regulation literature. It is also important to note that the actual practice of incentive regulation is considerably behind the theory. That is, many incentive mechanisms proposed have not been implemented or even seriously proposed and PBR does not include these more theoretical proposals. However, the basic theory of incentive regulation is useful for understanding the rationale behind PBR. In this regard, two economists, Laffont and Tirole (1993), present a simple but powerful model of incentive regulation and PBR:

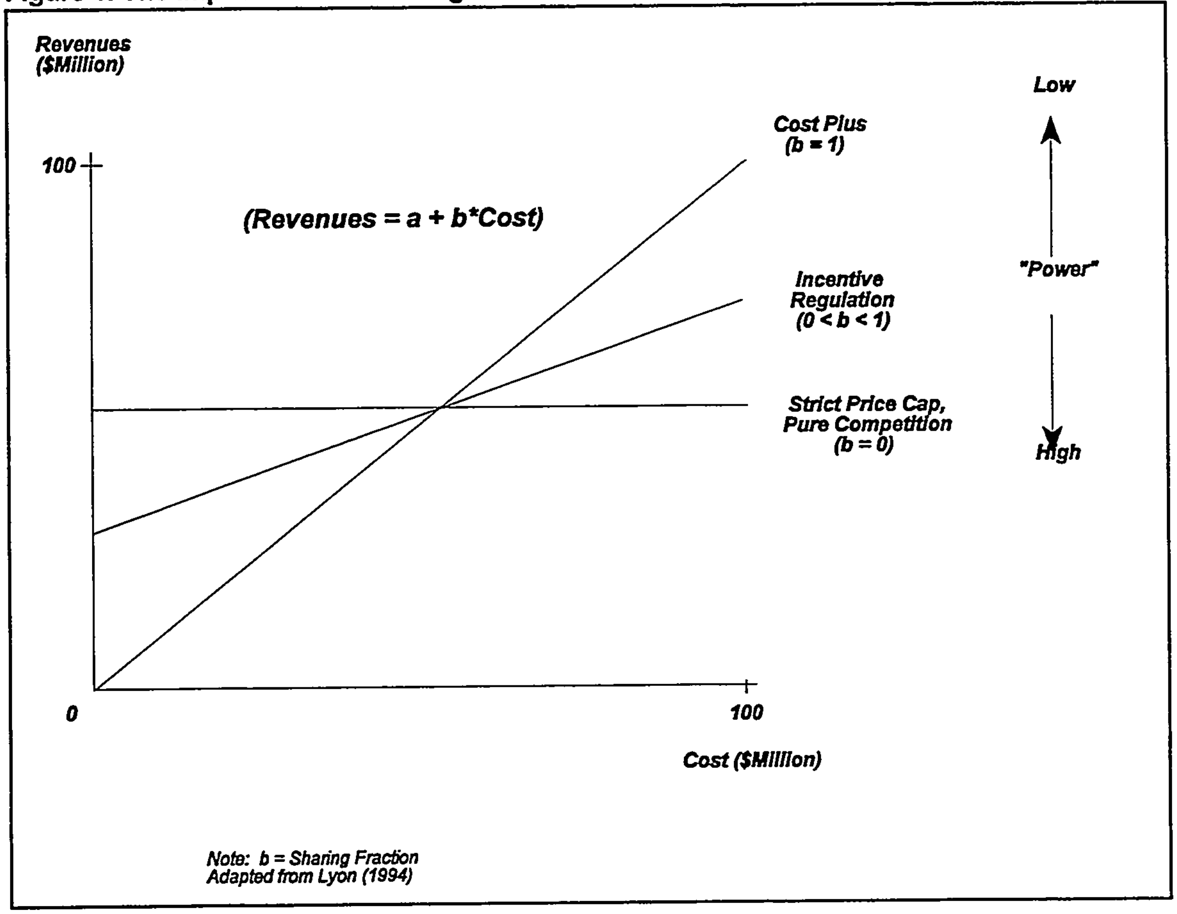
$$Revenues = a + b \cdot Costs \qquad (1)$$

where:

Revenues	=	actual (*ex post*) revenues received
a	=	fixed payment, set *ex ante*
b	=	*ex ante* sharing fraction, $0 < b < 1$
Costs	=	*ex post* costs

[1] By *improved* rates, we mean rates that accurately reflect the cost of a utility service delivered in an efficient manner.

Figure 1. The Impact of Cost Sharing on the Power of an Incentive Regulation Mechanism



Regulation becomes "incentivized" when a firm is given the financial incentive to minimize costs for a given good or service. The equation shows a relationship between *ex post* revenues and costs based on two parameters set *ex ante*, a and b. Laffont and Tirole show that a firm's incentive to minimize costs is inversely proportional to the magnitude of the sharing fraction, b. In other words, a firm's risk for cost overruns, and its ability to keep any cost savings, increases as b decreases. Laffont and Tirole call low-b plans *low-powered* and high-b plans *high-powered* (Figure 1). COS/ROR regulation with frequent rate cases may be though of as setting b = 1 and is, thus, a low-powered incentive mechanism. Fixed price contracts, COS/ROR regulation with infrequent rate cases, or price or revenue indexing represent various forms of medium- to high-powered incentive regulation; they increase the portion of revenues received through payments set *ex ante*, and decrease the portion of payments determined *ex poste*. Purely competitive markets, where the seller of a product or service cannot influence the market's price, represents another situation where the incentive powers are high. Because of this, PBR is often described as a way of making utility regulation mimic some of the incentives that operate in an unregulated competitive market.

High powered incentive mechanisms are not always preferable to low powered ones (Lyon

1994, pp. 4). High powered mechanisms rely heavily on the regulator's imperfect knowledge of customer demands and utility costs and, thus, increase uncertainty in utility profits. Thus, a mechanism with no adaptation to *ex post* costs will result in prices that are distorted and can threaten the viability of the incentive plan. An objective of designers of incentive regulation plans is to simultaneously improve the incentive power of the ratemaking process and make it adaptive enough to adjust for unforeseen events.

2.2 Traditional Cost of Service/Rate of Return Regulation

Before examining PBR mechanisms further, it is useful to have a common understanding of what business-as-usual regulation means. Price regulation of gas distribution companies varies by state, but most are forms of COS/ROR regulation. Ratemaking for a gas utility is usually done on two tracks: one for the company's margin (base rates) and another for its purchased gas costs and pipeline demand charges. For base rates, rate cases establish rates (by customer class) based on a utility's costs in a test year. Large capital additions are sometimes excluded from general rate cases and are included in rates via a separate proceeding. Large capital additions may also require approval before commencement of construction via Certificate of Public Convenience and Necessity (CPCNs) Proceedings. On top of the established cost of service, base rates are set to allow a utility a reasonable opportunity to earn a return on its invested capital. Rates for commodity costs and pipeline demand charges are usually separated from base rates and are included in a purchased gas adjustment (PGA) account, which receives frequent updating to reflect current gas commodity costs (Burns et al. 1991).

Like any regulatory framework, COS/ROR regulation establishes some performance incentives. First, although the informational asymmetry between the utility and the regulator makes it possible for the utility to inflate its costs, the traditional rate case allows PUCs an opportunity to disallow monopoly profits and operational costs that are clearly excessive. Indeed, it is the protection of consumers from the monopoly powers of public utilities that is a key rational for price regulation in general and the COS/ROR framework in particular. Second, base rate cases are not typically annual events; thus, utilities have an opportunity to capture some of the benefits from productivity improvements implemented between rate cases. This delay between current unit costs and regulated rates is known as *regulatory lag* and provides incentives to lower unit costs, especially the cost of nonfuel O&M and small capital additions. Prudence or reasonableness reviews on large capital additions and gas purchased costs are a third performance incentive existing in COS/ROR regulation. Prudence reviews are conducted on large capital additions because informational asymmetries can be great on these projects and, depending on the timing of rate changes to recover new large capital additions, regulatory lag may not exist. Reasonableness reviews are relied upon in the case of purchased gas costs because the frequency of rate changes from the now-common PGA clauses eliminates regulatory lag and its attendant incentives for cost minimization (Harunuzzaman et al. 1991).

As was already noted, this picture of traditional regulation is a simplification in light of state-to-state variations. Changes to traditional ratemaking are also occurring as a result of ongoing industry restructuring. In the domain of base rates, COS/ROR regulation remains the norm, but increased competition allowed by the new industry structure has led to changes in the way interclass cost allocations are made.[2] In addition, pricing flexibility for customer classes with alternative fuel capability or bypass opportunities is now widespread. With respect to gas commodity rates, the most dramatic impact of industry restructuring has been the increase in self-procurement by customers; many larger customers now bypass the LDCs' procurement function and state-regulated commodity rates altogether. For those customers that still buy bundled services from the LDC, PUCs still set LDC procurement rates, but changes in LDC responsibilities are forcing PUCs to change the way they regulate these rates. FERC Order 636 unbundled interstate pipeline services and eliminated or deregulated the pipeline's sales services and thus forced LDCs to be responsible for their upstream procurement decisions. As a way to address the added risk and complexity of LDC procurement, PUCs are considering changes to the traditional PGA rate and reasonableness review proceedings and are considering advanced approval of contracts or contract mixes, the development of less formal or informational proceedings, and eliminating or reducing the scope of PGAs.[3]

On balance, restructuring has not brought an end to COS/ROR regulation for LDC ratemaking. The stresses that is undergoing is causing increased consideration of PBRs, however, and thus leads to the examination of gas LDC PBRs in this report.

2.3 The Rationale for Performance-Based Ratemaking for Gas Utilities

PBR is of interest as a regulatory policy because it can potentially provide four types of benefits:

Resource Efficiency. Resource efficiency is the ability to provide a quantity of goods or services using a combination of inputs (e.g., labor, capital, and materials) that minimizes total cost. Further, resource efficiency also includes the ability to make cost-reducing investments (e.g., research, reorganizations, and capital equipment) that results in the provision of goods and services at the lowest possible cost over time.[4] PBR gives the utility a financial stake in improved resource efficiency because it gives the utility a greater share of any of the cost savings that result. To the extent that COS/ROR regulation is "cost plus" in nature, it limits the upside and downside returns of the gas LDC. Cost-plus regulation gives the LDC few incentives to make appropriate investments. Cost savings opportunities may be foregone or,

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2 See, for example, interclass reallocations that resulted from competitive pressures in California (CPUC 1992, pp. 1-8).

3 For a discussion of alternative methods of regulating gas procurement, see Goldman et al. (1993).

4 These two types of resource efficiency are sometimes called, respectively, "static" and "dynamic" efficiency (PG&E, 1994, pp. 5-4). Crew and Kleindorfer (1986), provide a discussion of resource efficiency using the terms *X-efficiency, dynamic efficiency, and scale efficiency.*

worse yet, investments may be made that provide negative net benefits.

To get an approximate sense of the opportunities for increased resource efficiency, costs (revenues) for a typical U.S. gas distribution utility are shown in Figure 2. Arguably, the costs that are most controllable by a gas utility's managers are its nonfuel operations and maintenance (O&M) expense and its expenditure on plant. These costs amount to 21 percent of U.S. gas LDC industry revenues in 1992 (Figure 2).[5] The second area of costs an LDC has some control over is purchased gas costs. Even with the advent of customer-owned transportation, purchased gas costs are still the largest expense category for gas LDCs, accounting for 60 percent of industry revenues. Taxes, interest, and ROE would be relatively insensitive to PBR mechanisms and they account for 19 percent of industry costs.

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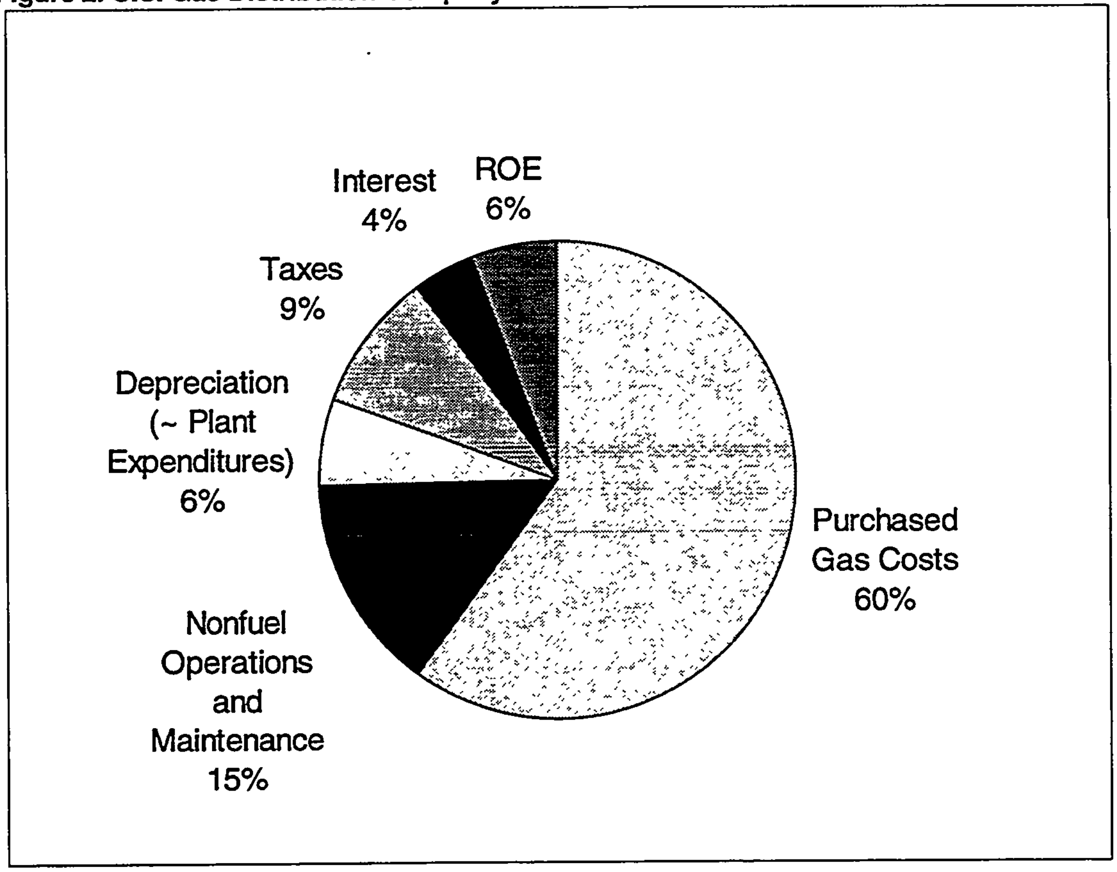
5 Depreciation does not necessarily equal annual investment expenditures. However, AGA data indicates that current industry depreciation matches current annual investment expenditure (AGA 1993).

Figure 2. U.S. Gas Distribution Company Revenue Breakdown– 1992



Allocative efficiency. Allocative efficiency is achieved when an economy maximizes the total value of output (Scherer and Ross 1990, pp. 27). This efficiency is achieved or improved when prices for goods and services are set at marginal cost or as close to marginal cost as possible subject to a revenue requirement constraint. Regulators can improve allocative efficiency by giving LDCs pricing flexibility in conjunction with safeguards against excess profits. PBR combined with pricing flexibility can improve the utilization of existing assets or capacity holdings because it allows the utility to retain fuel-switchable customers, trade capacity holdings, and promote off-peak usage. Major stumbling blocks of pricing flexibility—*i.e.*, whether such flexibility will allow the utility to earn monopoly profits and whether such flexibility will harm captive customers—are overcome when pricing flexibility is proposed in conjunction with PBR. Under PBR, the ratemaking index formula along with any earnings sharing mechanism ensures against monopoly profits. Further, any revenue shortfall from discounting is not automatically allocated to captive customers, so shareholders are unlikely to make discount decisions that harm captive customers.

Introduction of New Services. Just as PBR can reduce the complexity of the allocation of costs when some services are discounted, PBR can facilitate the introduction of new, nonmonopoly products and services. PBR should reduce the need to discuss the allocation of utility common costs to a new service since the allocation of common costs to monopoly services is implicitly set by the PBR. Thus, utilities should see reduced regulatory risk from "expropriated" profits from the introduction of new services.

Administrative and Regulatory Costs. PBR can in theory reduce the cost of regulation incurred by the PUC, the utility, and other intervenors. While the initial proceeding that determines and implements the incentive mechanism can be costly, regulatory costs can be decreased if the frequency or complexity of future rate cases is reduced. Administrative cost benefits may be seen as a direct result of the fact that PBR recognizes the informational asymmetry between the regulator and the utility. Under traditional COS/ROR regulation, considerable effort and expense is made by the regulator to bridge the information gap. PBR, by focusing on performance more than costs, reduces the need to rectify the asymmetry.

Although not a separate rationale, it is safe to say that PBR is most often considered as a regulatory option when a utility faces competition and restructuring in one or more of its business segments. This is often the case even when the utility currently retains market power in the business area where PBR is being proposed. At first, the association PBR of competition and restructuring proceedings appears counterintuitive. Retention of COS/ROR regulation for monopoly services would appear sufficient considering the effort required to unbundle competitive services from monopoly ones. However, competition and restructuring often increases the complexity of the allocation of utility facility costs used for both competitive and noncompetitive services. Thus, sticking to COS/ROR ratemaking in such an environment may require considerable work and may result in more distorted prices. Furthermore, the *future* boundary between competitive and monopolistic services is often blurry. Thus, one may see the association of PBR with competition and restructuring as a way for regulators and the industry to (1) allocate costs among services without resorting to ever more complex, contentious rate hearings and (2) increase the incentives for resource efficiency in light of an eventual conversion to partial or complete deregulation.

Although the rationale behind PBR has resulted in considerable interest on the part of regulators, it is far from universally accepted. Even its supporters would agree that there are several competing PBR mechanisms and that few have been adequately tested. Thus it would be incomplete to end a discussion of gas utility PBR without a discussion of its potential *pitfalls.* This is done in the final section of this report, after it has discussed a typology of PBR and several key design issues.

3 Typology of Gas LDC PBR

Table 2 provides a typology developed by LBL for understanding the types of PBR proposals made by gas utilities. PBR plans may be broadly categorized by the utility service covered (transportation/distribution, procurement, or both) and the PBR's scope within those service categories (broad or narrowly-targeted). In the following subsections, different types of PBR identified in the typology are defined and described. The utilities in the sample that have sponsored a particular type of PBR are also identified.

3.1 Base Rate Incentive Mechanisms

Five utilities (Wisconsin Gas, NJNG, SDG&E, BUG and PG&E) have proposed PBR plans that cover base rates or base-rate revenue requirements separately from any ratemaking treatment on procurement costs (Enright 1993; Matthews 1993; NJNG 1993; SDG&E et al. 1993; Wisconsin Gas Company 1993; Pacific Gas and Electric Company (PG&E) 1994).[6] All of these plans are considered to be "broad"; *i.e.* the incentive plans cover most or all base rate expenses. The typology proposed in Table 2 and the discussion below further differentiates broad, base rate PBRs according to whether the index mechanism focuses more on rates or revenues.

Rate Freezes, Rate Indexes, and Price Caps

Incentive mechanisms that provide formulas for the determination of rates constitute a well-known type of incentive mechanism. Rates set by traditional rate cases are avoided and are, instead, either indexed or frozen The most common conceptual model for rate indexing is based on the "telecommunications style" price index formula (Beesley and Littlechild 1989):

$$P_{m,t} = P_{m,t-1} \times (1 + I - X) + Z \qquad (2)$$

where

m	=	service category or pool
t	=	year
Pm,t	=	Price for service m in year t
I	=	inflation (rate of change of applicable price index) (%/year)
X	=	productivity offset (%/year)
Z	=	allowable unit cost adjustment for unforeseen event

6 The description of SDG&E's base-rate plan is based on joint testimony filed by SDG&E and the California Public Utilities Commission's (CPUC's) Division of Ratepayer Advocates.

With a telecommunications-style index formula, maximum rates for a particular service

Table 2. Typology of Gas Utility Ratemaking Incentive Mechanisms

	Scope	
Utility Service Category	Broad	Targeted
Base Rates (On-system Transportation, Distribution, and Storage)	• Rate Freeze/Index/Cap (Wisc. Gas, NJNG) • Revenue Index (SDG&E, BUG, PG&E)	• Specific Base-Rate Cost Incentives (BUG) • Targeted Throughput Incentives (BUG, NJNG)
Procurement (Gas Supply Costs)	• Unit Cost Indices/ Benchmark (SoCal, SDG&E)	• Targeted Procurement Cost Incentives (MichCon, NJNG)
Comprehensive (Transportation/Distribution & Procurement)	• Unit Cost Index (NMGas) • Rate Comparison (NJNG) • Bill Comparison (PG&E) • Service Quality Indices (BUG, NMGas, NJNG, SDG&E, PG&E)	• DSM Performance Incentives (SDG&E, SoCal, PG&E)

Note: Utilities with proposals that exemplify a particular type of incentive mechanism are noted in parenthesis.

or pool of services are indexed according to inflation, I, a productivity offset, X, and, possibly, an allowance for unforeseen events, Z. If no pricing flexibility is allowed, the index determines the rate. More generally, the index is used only to set the price cap, and the utility is allowed to flexibly price below the cap. Upward pricing flexibility on individual services may also be allowed if the cap is applied to a pool or "market basket" of services.

In this report's sample, two utilities, NJNG and Wisconsin Gas, proposed forms of rate indexing that are in the spirit of Equation 2 but with some important differences. NJNG proposed to index or freeze most aspects of its revenue requirement. Further, the company would be held to its last test-year sales forecast, with certain adjustment for weather-related sales variations. Thus, its plan constitutes a rate index. Wisconsin Gas's proposal is closer to a real price cap. Individual class average rates would be indexed using a formula similar to Equation 2. Both utilities asked for increased pricing flexibility as part of their rate indexing proposals.

Rate freezes are a special case of rate indexing. Rate freezes imply that X is set equal to I for the incentive ratemaking period. The mechanics of implementing rate freezes are simpler than indexing, and freezes have resource efficiency properties similar to price caps. Although Wisconsin Gas proposed a rate index, the Wisconsin Public Service Commission (PSC) adopted a rate freeze instead of a rate index. The Wisconsin PSC chose a rate freeze over an index primarily because it was concerned over the legality of a rate index that could possibly lead to rate increases without a hearing. Rather than be forced to conduct annual hearings to approve changes indicated by the index or risk legal challenges, the PSC chose a rate freeze (Wheeler 1994).

The most ambiguous term in Equation 2 is the allowance for unforeseen events, Z. In theory, cost changes that are not reflected in I or X and are beyond utility management's control could be allowed into rates via the Z factor. A commonly cited example of a Z factor is a change in the tax law that affects costs of the regulated industry more than the general economy. In practice, determining which cost changes are beyond management control and which factors are not already included in the I and X factors is very difficult. How the base-rate PBRs handled Z factors is discussed further in Section 4.2, below.

Base Rate Revenue Indices

Incentive mechanisms based on revenue indices have many similarities with rate indexing mechanisms. The key difference is that the index focuses on authorized revenues rather than rates. Final rates charged may be subject to traditional ratemaking procedures of throughput forecasting, cost allocation, and rate design. Thus, while the company may be held to its overall expenses for a particular cost category, such as labor expenses, it is not at risk for throughput and, further, may have some ability to change the customer class that is allocated an expense. Because of these differences, revenue indices may be seen as a less powerful although perhaps more feasible, form of PBR.

Revenue index formulas may be stylized with the following equation:

$$R_{n,t} = R_{n,t-1} \times (1 + I - X) + Z \tag{3}$$

where:

n = base-rate cost category
t = year
Rn,t = Revenue for category n in year t
I = inflation (rate of change of applicable price index) (%/year)
X = productivity offset (%/year)
Z = allowable cost adjustment for unforeseen event

Compared to Equation 2, Equation 3 indexes revenues rather than rates. Further, revenue indices are more commonly broken out into cost categories rather than customer-class or service categories.

Three utilities in the sample have base-rate revenue index proposals: PG&E, SDG&E, and BUG. PG&E and SDG&E's proposals eliminate the portion of rate cases that determine gas department base-rate revenues, but the proceedings that allow for cost allocation and sales forecasting are preserved. BUG's proposal specifies how to set final rates based on the indexed revenue requirement, but because sales figures are updated annually, its proposal does not qualify as a rate index.

Targeted Base-Rate Incentives

It is possible to narrowly target incentives on specific aspects of base-rate performance. Targeted incentives may focus on throughput, specific base-rate costs, or both. Targeted cost incentives identify a cost item and establish a benchmark. A bonus or penalty is provided if costs are below or above the benchmark, respectively. For the targeted cost incentive to qualify as PBR, the bonus or penalty should be greater than the margin impact that would accrue to the utility under traditional regulation.

Targeted throughput incentives establish target throughput levels and incremental revenues above or below this target are shared in some manner. Usually targeted throughput incentives are limited to new services or services to classes for which it is difficult to forecast demand. This limitation is important because under traditional COS/ROR regulation, a utility should be able to keep *all* incremental margin from higher throughput. Targeted throughput incentives that share revenues only make sense as a form of PBR if they facilitate the process of getting the utility into the new markets or eliminate a contentious and costly hearing over throughput targets.

There are probably many utilities that have targeted base-rate incentive mechanisms of some kind; they are not well represented in the sample, however, because the focus of this report is on utilities that proposed broad incentive mechanisms. Two utilities (BUG and NJNG) have components of their incentive plans that identify incentives for improved performance on either particular base-rate cost items (e.g., the cost of complying with a new, potentially avoidable local ordinance) or share revenues from new services (e.g., capacity release, wholesale transportation) or share revenues from hard-to-forecast services (e.g. service to customers with alternative fuel capability).

3.2 Procurement Incentive Mechanisms

As was described in Section 2, the ratemaking status quo for an LDC's procurement costs is very different from the status quo for base rate costs. Frequent updating of procurement costs via PGA clauses reduces an LDC's exposure to risk. With this starting point, a return to commodity rates set in infrequent rate cases would be a form of PBR because it would bring back the incentive forces of regulatory lag. The volatility of gas commodity prices, however, makes the full elimination of PGA clauses unlikely. A more viable alternative is to reduce the fraction of cost changes that can be passed through PGA clause and increase the amount of revenues that are tied to external benchmarks of gas supply costs. The three commodity PBR proposals described in this report take this approach; PGAs are retained, but market-sensitive benchmarks are used as the basis for incentives or penalties applied on top of the PGA-adjusted revenue.

As with base rates, incentives for gas supply costs may be distinguished between ones that are targeted and ones that are broad in scope. Targeted procurement incentive mechanisms are not discussed in this report, except for Michigan Consolidated Gas Co.'s (MichCon's) proposal to share the gains or losses from utility activity in the futures market. The following describes two broad procurement incentive mechanisms.

Broad Procurement Incentives: The California Gas Cost Incentive Mechanisms

Two utilities in the sample, SoCal and SDG&E, currently operate with incentive mechanisms that are tied to broad indices of procurement costs. SoCal had its Gas Cost Incentive Mechanism (GCIM) adopted in 1994, based on a proposal SoCal filed in 1993 (SoCal 1993; CPUC 1994). The CPUC adopted, in June 1993, a similar procurement incentive mechanism for San Diego Gas & Electric Co. (SDG&E), based on an application SDG&E filed in 1992 (CPUC 1993). The breadth and the general methodology of the SoCal's proposal and SDG&E's adopted plans are similar. First, an index of gas supply costs is constructed using tariffed pipeline rates and market prices for the gas supply. The benchmarks rely on prices for short-term firm supplies as reported in trade publications. SoCal's benchmark is also based on New York Mercantile Exchange (NYMEX) futures prices. Utility actual costs are compared to the benchmark.[7] Actual costs above the benchmark are passed through up to a tolerance level above the benchmark.[8] For costs above the benchmark plus tolerance, shareholders must absorb some of the excess costs. The purpose of the tolerance band is to keep the utility from being unfairly penalized for any pre-existing, non-market-responsive contracts in its portfolio or to allow it to buy at a small price premium if necessary to ensure reliability. If actual procurement costs are below the benchmark, the savings are shared between ratepayers and shareholders. SoCal's incentive mechanism has an additional feature that shares, between ratepayers and shareholders, incremental gains or losses made by using storage facilities to lower supply costs. A key feature of both procurement incentive programs is that PUC reasonableness reviews of gas purchases subject to the incentive mechanism are

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7 SoCal's mechanism excludes gas supply contracts from affiliated suppliers and a certain number of pre-approved long-term supply contracts.

8 SDG&E's procurement incentive mechanism is based on two benchmarks. Benchmark A measures prices in the supply basins from which SDG&E buys and cost sharing occurs when SDG&E buys below Benchmark A or above Benchmark A plus a tolerance. Most of the potential incentive payments are tied to this benchmark. Benchmark B measures SDG&E's costs at the California border (supply plus transport costs). There is no penalty to SDG&E for failing to meet the benchmark, only a reward (5% of savings) for beating it.

eliminated.

There is only limited information on the results of these procurement incentive mechanisms. SDG&E, during the first year its incentive mechanism beat its gas supply benchmark by 2.5 percent (Savage 1994).[9] SoCal, making a backcast of its performance against the benchmark from a recent year, estimated its actual costs to be 1.0 percent higher than its benchmark.

3.3 Comprehensive Incentive Mechanisms

Comprehensive incentive mechanisms are defined here to cover performance in both transportation and procurement services. Several types of incentive mechanisms proposed by the sample utilities fell in this category. First, Niagara Mohawk Power Corporation's Gas Department (NMGas) operates under a comprehensive incentive mechanism that is based upon a unit cost index. The unit cost index measures utility performance in providing both sales and transportation services and this index is compared to a similar index constructed for a set of peer utilities. Second, at least one utility (NJNG) proposed an incentive tied to a ranking of average residential gas rates. Third, PG&E proposed an incentive tied to its performance of average customer bills. Fourth, five utilities (BUG, NJNG, PG&E, SDG&E, and NMGas) propose incentive mechanisms tied to one or more measures of service quality. Service quality incentives are shown in Table 2 as neither broad or targeted; their scope depends greatly on the number and type of performance indicators chosen.

Shareholder incentives for utility DSM performance exist for some gas utilities in the U.S., including California's investor-owned gas utilities. Such incentives are "comprehensive" in the sense that DSM programs sponsored by the utility avoid utility procurement costs and base-rate costs. They are targeted, however, in that they focus on only one portion of a utility's operations. The typology proposed in Table 2 lists DSM shareholder incentives as a targeted, comprehensive incentive.

The following briefly describes one of the more novel comprehensive incentive mechanisms in the sample: NMGas's comprehensive unit cost index.

External Unit Cost Indices: The NMGas MERIT 2B Goal

NMGas's Measured Equity Return Incentive Term (MERIT) Goal 2B covers both base rate and procurement costs in one comprehensive unit cost index. A similar incentive mechanism (MERIT Goal 2A) has also been adopted for Niagara Mohawk's electric department. These unit cost indices are part of a set of 12 performance goals included in the MERIT program. The Goal 2A and 2B incentive mechanisms are novel both in terms of their

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9 SDG&E beat its border benchmark (Benchmark B) by 8.9%. This higher figure is a result of SDG&E beating its transport subindex by a wide margin. Because of the difficulty of developing an accurate external benchmark for transport costs, only 5% of Benchmark B net benefits are passed through to shareholders.

comprehensiveness and the detail of the external data employed (Lowry 1991; Lowry and Hovde 1994).

NMGas is subject to traditional COS/ROR regulation on base rates and a PGA-like mechanism on its procurement costs and the MERIT Goal 2B mechanism does not change these mechanisms. The incentive payment, if earned, is added to revenues the company recovers from its authorized rates. The incentive mechanism offers rewards only; there is no penalty for poor performance.

NMGas's incentive mechanism was implemented in 1993 and uses 1992 as a base year. A unit cost index (UCI) was developed for NMGas gas department. This index is compared to a similarly defined external cost index (ECI) of a peer group of 14 utilities from the U.S. Northeast. Service outputs in both the UCI and ECI are revenue weighted; that is, the output of services with higher prices, such as residential sales services, are weighted more than an equal quantity of lower-price services, such as interruptible transportation. Revenue weighting helps eliminate a potential bias of a comprehensive index. An unweighted comprehensive index, such as a simple average-cost or average-price index, could give a utility a windfall if it unbundles procurement and transportation services more rapidly than the utilities included in the external index.

Data for the unit cost index is taken from the Uniform Statistical Reports (USRs) which certain LDCs file annually with the American Gas Association. Additional data from federal government surveys (e.g., EIA, BLS) and other publicly available sources are also used in the index.

NMGas determines its incentive payment by comparing changes over time between NMGas's UCI and its ECI. The ECI is ultimately computed using the same type of data as the UCI. USR data for the peer utilities are not available until the ninth month after the end of a year, however, which reduces to the power of the ECI as an information tool for utility managers. To mitigate this time lag, NMGas compares its UCI to a *preliminary* ECI that is based on more-readily-available external data and a fixed productivity factor. Incentive payments are based on the rate of change of the ECI relative to the NMGas's UCI. Incentives are paid to the extent the ECI grows faster than NMGas's UCI. NMGas cannot obtain an award for starting off with lower unit costs; it must improve its unit costs relative to the external group of utilities and maintain that edge over the three year period.

Results of the MERIT 2B program are available for its first year, using the preliminary ECI. NMGas's unit cost index fell by 1.0 percent and the preliminary ECI rose by 6.9 percent. Thus, relative to the external cost index, NMGas posted a 7.9 percent gain (Garguil 1994). Actual awards ultimately depend on the relative standing of the unit and external cost indices at the end of the three year period. The maximum incentive payment is equal to a 4 basis point added to annual gas department ROE and will be paid out if NMGas's UCI grows slower than the ECI by at least 2.0 percent/year over the three-year period. Given that NMGas posted a 7.9 percent gain in the first year, it appears well on its way towards earning the full incentive payment.

4 Observations Regarding Pivotal Design Issues

As is readily apparent from the description of sample incentive ratemaking plans in Table 1, PBR for gas utilities is in a very early stage. Detailed analysis of results under the incentive plans is not yet possible. At this stage of development, however, features of the various plans may be compared and emerging themes put forward. This section attempts to do this in the following manner. First, PBR plan terms are considered. Term (the length between rate proceedings) is one of the most simple, and yet important parameters of a PBR plan. Second, there are several issues that are of particular importance to base-rate plans. These issues include whether weather adjustment mechanisms are included, the choice of inflation and productivity factors, the treatment of gross plant additions, and the choice of earnings sharing mechanisms, off ramps, and Z factors. All of these issues are discussed. Third, procurement incentive mechanisms, which attempt to tie utility revenues to observable but volatile gas commodity markets, raise issues of their own. Fourth and finally, PBRs cannot ignore a utility's performance in the areas of quality, reliability, and energy efficiency. How PBRs handle these "nondollar" service goals is addressed in the final subsection.

4.1 PBR Plan Terms

One of the most important aspects of a PBR plan is its term; *i.e.,* the duration of time that the plan will be in effect. In general, the longer the term of an incentive ratemaking plan, the more powerful will its incentive properties will be. The five base-rate PBR plans have terms ranging from three to six years (Table 1). Whether these terms are long or short depends, in part, on the regulatory status quo. BUG and NJNG proposed plan terms of three and four years, respectively. Apparently they are free, in the absence of PBR, to make annual rate filings if they want. Gas utilities in Wisconsin and California are generally subject to two- and three-year rate case cycles, respectively.[10] Thus, the terms for the plans of Wisconsin Gas, PG&E, and SDG&E– four, six, and six years– respectively, represent a doubling of the status quo. As shown in Figure 3, these base rate plans indicate that, on balance, PBR can improve the minimum length between rate cases.

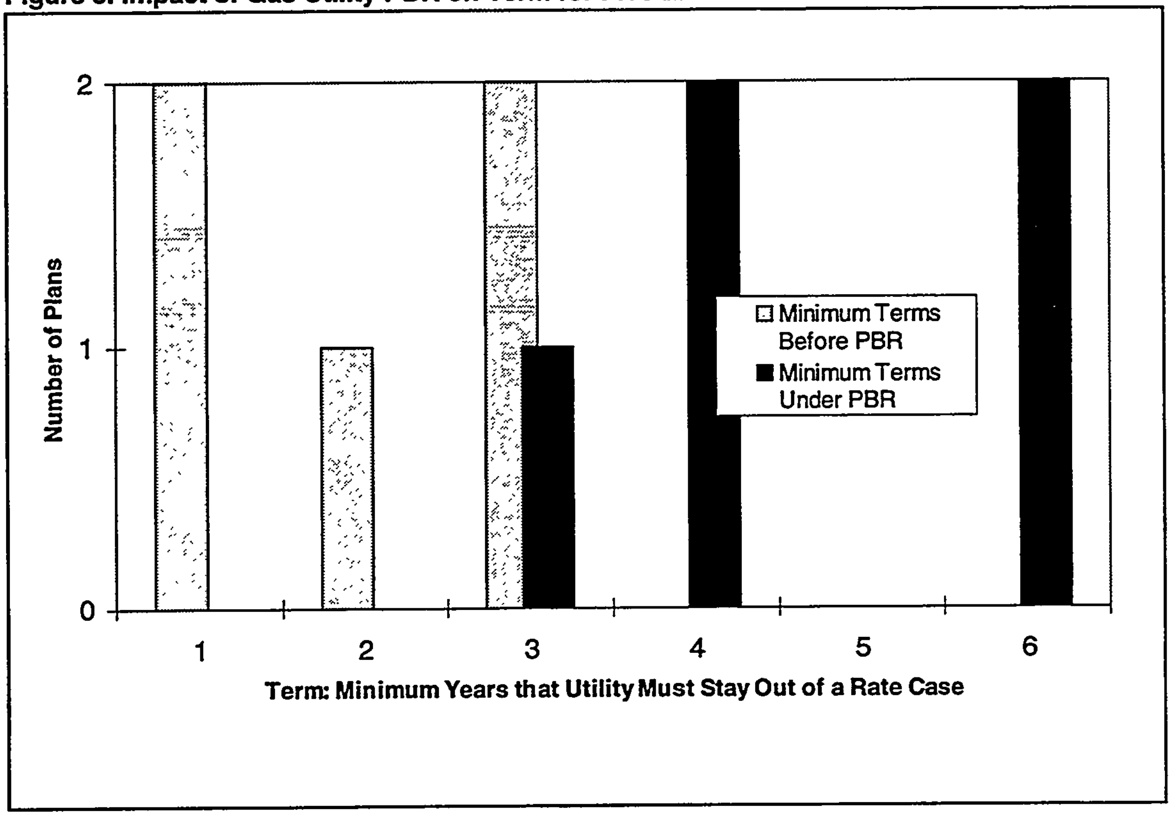
For the two broad procurement incentive plans, SDG&E's and SoCal's, terms are two and three years, respectively. For SDG&E and SoCal, the status quo is a full PGA, so deviations between procurement costs and rates is accounted for monthly. Although customer rates are adjusted annually, it is as if, from a utility risk perspective, rate changes occur monthly. Thus, the broad procurement plans represent a two- to three-year extension of term relative to the

10 The biennial rate case cycle for energy utilities in Wisconsin represents a recent change. Previously, annual rate cases were the norm.

status quo.

The NMGas comprehensive incentive mechanism has a term of three years. However, the incentive mechanism supplements existing ratemaking practices so this PBR does not affect ratemaking term.

Figure 3. Impact of Gas Utility PBR on Term for Five LDC Plans



4.2 Base Rate Design Issues

Weather Adjustment Mechanisms: A Common Feature of the Base-Rate Plans, But Are They Necessary?

All but one of the sample utilities have requested, or have already implemented, weather adjustment mechanisms for firm, temperature-sensitive customers.[11] Weather adjustment mechanisms track revenue surpluses or shortfalls attributable to weather variations and adjust rates (either immediately or after a time lag) to ensure the utility recovers these revenues.

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11 For a discussion of weather adjustment mechanism and a national survey of their usage, see Marple (1991 and 1992).

NJNG and BUG requested already-existing weather adjustment mechanisms be continued as a part of their incentive plans. Wisconsin Gas proposed a weather adjustment mechanism as a part of its plan although the Wisconsin PSC rejected this aspect of Wisconsin Gas's plan. For several years now, SDG&E, SoCal, and PG&E have had full revenue decoupling for its core customers and partial decoupling for its noncore customers; thus, they too are at little or no risk for weather-related sales variations.[12] Finally, NMGas implemented a weather normalization clause effective February 1994, although the justification for the mechanism was made independently of NMGas's comprehensive incentive mechanism.

Weather adjustment mechanisms can significantly reduce the revenue and earnings variation for a utility. This is because many utility base rate expenses are driven by nonthroughput-related factors such as the number of customers and customer density. Because the weather is outside a utility's control, it is argued that weather adjustment mechanisms are reasonable because they can reduce a utility's cost of capital.[13] Although weather adjustment mechanisms are not the norm in the U.S., their use by utilities appears to be growing (Marple 1992). An important question is whether weather normalization mechanisms are a necessary condition for incentive ratemaking. In theory they should not be, so long as sales forecasts used to compute rates are unbiased. To the extent that gas utilities have been able to mitigate weather-related sales risk in the past, they should be able to mitigate it under a system of indexed prices or revenues. This is especially true if the term of the incentive ratemaking plan is long relative to normal weather cycles because the utility will have the ability to balance weather-induced earnings windfalls with shortfalls. As a practical matter, however, it appears likely that utilities pursuing PBR will propose them in conjunction with weather adjustment mechanisms. Few utilities appear willing to accept a PBR plan's "stay out" provision that precludes the option of filing frequent rate cases. Utilities' linking of incentive plans to weather adjustment mechanisms has some merit considering that the proposed base-rate plan terms (three to six years) are not long relative to the length of temperature cycles that can appear in the weather.

Inflation and Productivity Offsets: A Wide Range of Levels Are Proposed

The five base rate incentive plans all rely on inflation factors and productivity offsets to compute rates in future years. Also, NMGas's comprehensive index relies on a preliminary estimate of its external cost index (ECI) that is computed using an inflation factor and a productivity offset. Table 3 shows a wide variation in utilities' choices of inflation factors, productivity offsets, and the share of revenues subject to indexing. A few common themes

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12 Core customers are customers that generally take bundled and procurement and transportation services from the LDC. In California, core customers have been traditionally defined as customers with annual demands of less than 250,000 therms per year.

13 Whether cost-of-capital impacts from weather adjustment mechanisms are reflected in rates is an open question. Also, it should be noted that it is possible to mitigate earnings variations by changing rate design; *i.e.*, by imposing higher customer charges.

are, however, apparent

First, all utilities except NJNG proposed (or eventually agreed to) inflation factors based on external price indices. External, rather than company-specific, price indices are better because they increase the incentive properties of the ratemaking plan. Table 3 shows that utilities have proposed using many types of price indices for developing their inflation factors.

Second, all of the plans rely on fixed productivity offsets and most of these offsets are based on long-term gas- or energy-utility trends. Three utilities, SDG&E, PG&E, and NMGas, propose productivity offsets that are based on historical estimates of productivity. PG&E and NMGas's productivity offsets are based on energy utility trends, and SDG&E's is based on a broader measure of productivity in the economy (nonfarm labor productivity). Wisconsin Gas's initial productivity offset was based on a gas-utility-specific study, but was later revised upward to incorporate an internal productivity offset based on the expected benefits of a planned restructuring. The basis of the productivity offsets for BUG and NJNG are not known.

Third, Table 3 shows a wide range in the revenues subject to indexing. NMGas's index covers all revenues, including procurement costs. Wisconsin Gas's and PG&E's index covers all base-rate revenues. SDG&E, NJNG, and BUG chose inflation-productivity formulas for its nonfuel O&M costs only. How these last three utilities treat capital-related base rate expenses is discussed further in the next section.

Table 3. Comparison of Inflation Indices and Productivity Offsets Used in Gas Utility Incentive Ratemaking Plans

a. Rate Indices

$$P_{m,t} = P_{m,t-1} \times (1 + I - X)$$

Utility	Pm = Applicable price or unit cost	I = Inflation factor	X = Productivity Offset (%/yr)	Basis of Productivity Offset
NMGas	LDC unit cost index	four input price indices	0.3	total factor productivity estimate based on 18 Northeast U.S. LDCs, 1986-1993
Wisconsin Gas, initial filing	base rates	GNPPI	0.5	0.2 (based on a sample of seven U.S. LDCs, 1978-1992) plus a 0.3 "stretch"
Wisconsin Gas, revised filing	base rates	GNPPI	3.0	internal estimate based on planned co. restructuring
NJNG	labor O&M	co. specific wage rates	0.5	unknown
NJNG	nonlabor, nonfuel O&M	CPI	0.5	unknown

b. Revenue Indices

$$R_{n,t} = R_{n,t-1} \times (1 + I - X)$$

Utility	Rn = Applicable revenue category	I = Inflation factor	X = Productivity Offset (%/yr)	Basis of Productivity Offset
SDG&E (utility-staff stipulation)	total O&M *per customer*	various external price indices	1.5, at a customer growth rate of 1.5% per year	nonfarm labor productivity, 1960-1990
BUG (utility-staff stipulation)	total O&M	GDP price deflator	1.3	negotiated between utility and PSC staff
PG&E	total base-rate revenues, *per customer*	CPI-U	1.2	represents the "high end" of the empirical evidence on utility industry productivity growth

Notes: CPI = Consumer Price Index; CPI-U = Consumer Price Index, Urban Consumers; GDP = Gross Domestic Product; GNPPI = Gross National Product Fixed-Weight Price Index; O&M = operations and maintenance expense (excluding fuel costs)

Allowances for Capital Additions: Three Plans Propose Very Different Mechanisms

Three of the five base-rate incentive plans have separate ratemaking mechanisms for capital additions. Two, SDG&E and NJNG, can both be considered forms of incentive regulation, and BUG's mechanism can best be described as a form of COS/ROR regulation.

In SDG&E's PBR, gas plan net additions are fixed in each year of the PBR according to the following formula:

$$GPNA_t = GPNA_{t-1} \cdot (1.029 + 0.3 \cdot \%\Delta Cust) \cdot (1 + I) \tag{4}$$

where:

GPNA	=	gross plant net additions
t	=	year t
%ΔCust	=	change in the number of customers (%/yr)
I	=	inflation (percent annual change in construction cost index) (%/yr)

Equation 4 shows that capital addition revenues grow at a fixed amount (2.9 %/year) with additional allowances made for customer growth and inflation. The coefficients of the equation are based on a regression of company-specific data over a 40-year period. No explicit productivity factor is added although any productivity that SDG&E has achieved during the historical period is reflected in the coefficients.

NJNG's incentive mechanism is simpler and less powerful. COS/ROR ratemaking is the starting point for capital additions. On top of that, NJNG proposed a modest incentive on capital additions associated with new customers. NJNG distinguishes between capital additions for new customers and additions for system integrity. For new customer capital additions, a target per-customer cost of $2,300 is identified. This includes the costs of new customer main extensions, service lines, meters, and regulators. NJNG's actual capital addition costs per customer are examined in each year of the PBR. For every $100 that it beats the target number, it receives a 10 basis point increase in its benchmark rate of return. Given historical customer growth rates on the NJNG system, this basis point enhancement translates into a shareholder sharing fraction of 36%. For system integrity capital additions, which appears to include all other network capital additions, an explicit pass through of costs is proposed. That is, NJNG proposes to eliminate regulatory lag and be allowed to recover all capital additions not related to new customers.

Finally, BUG's multi-year rate plan addresses capital additions, although it is basically allows the utility to pass through all plant additions subject to the condition that additions in any year cannot exceed 115% of the base test year expenditures and that forecasted budgets are to be reviewed by staff and other intervenors. This mechanism may be best described as

COS/ROR with little or no regulatory lag.

Earnings Sharing Mechanisms: A Popular Adjunct to Base Rate Incentive Plans

Earnings sharing mechanisms track actual earnings and share with ratepayers any earnings that fall below or exceed certain thresholds. Mechanically this is done by accruing the excess or shortfall earnings in a tracking account and adjusting future rates to amortize the balance in the account. Earnings sharing mechanisms are not a separate form of PBR; rather, they may be seen as mechanism that supplements the basic incentive ratemaking mechanism. By sharing earnings with ratepayers, earnings sharing mechanisms can dilute a utility's incentive to improve productivity. In theory, it is better to set an aggressive productivity target than to give ratepayers a share of excess profits.[14] Despite their ability to reduce the power of the incentive mechanism, earnings sharing mechanisms are popular. Both of the broad procurement incentive mechanisms and four of the five base-rate incentive mechanisms include earnings sharing mechanisms. Earnings sharing mechanisms are popular because they provide insurance against "unacceptable" outcomes that could result from a mechanistic incentive ratemaking process. Extraordinarily high earnings can result not from exemplary performance but from poorly selected throughput or productivity targets. Even if large profits *are* deserved, they can lead to customer backlash that may lead to an incentive mechanism's demise. Conversely, a utility that performs poorly will naturally try to suspend the mechanism and seek rate relief. PUCs, which have obligations to preserve the financial integrity of the companies they regulate, cannot easily ignore such requests.

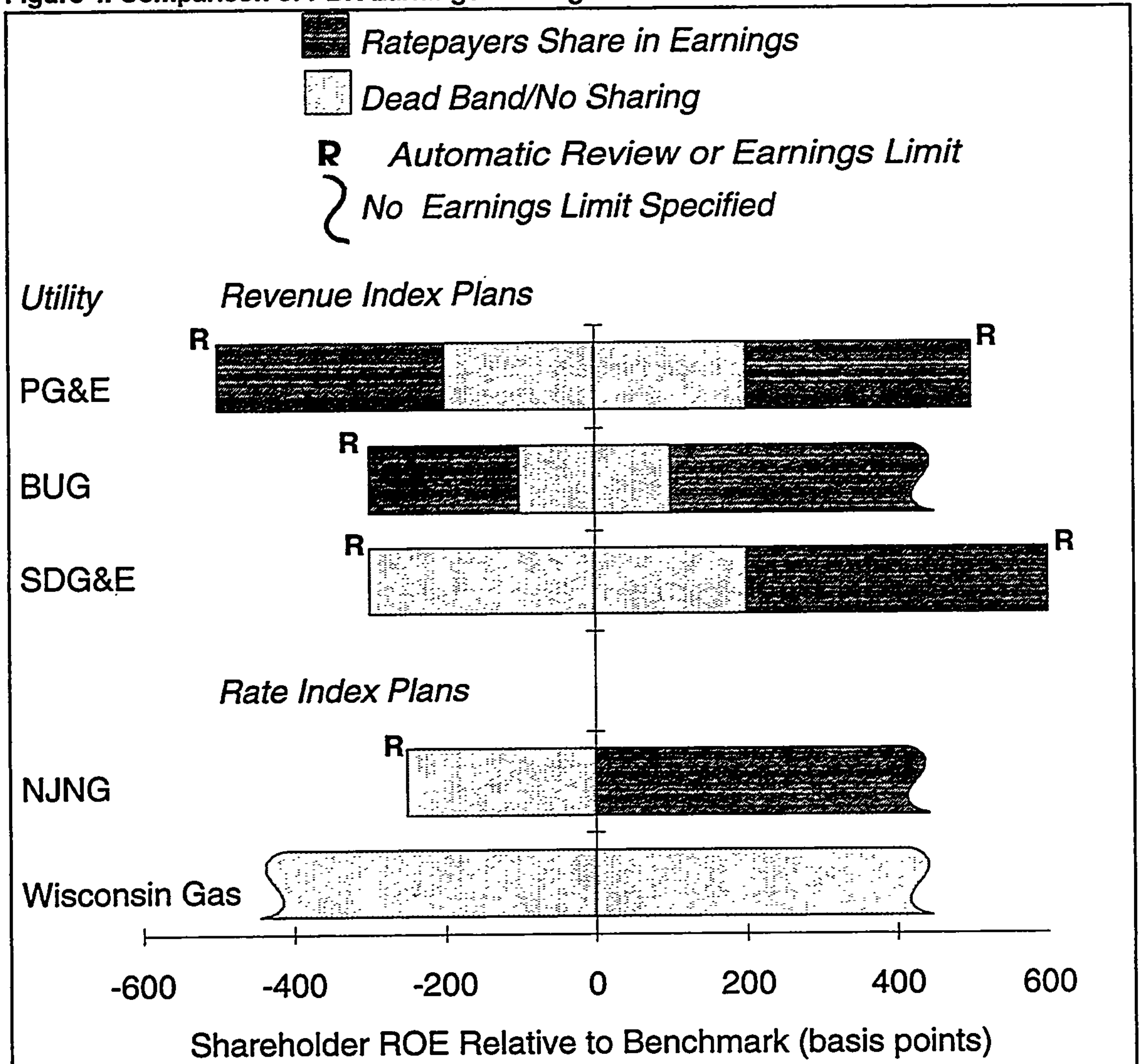
Of the five base rate incentive plans reviewed in this report, only Wisconsin Gas's does not include an explicit earnings sharing mechanisms (Figure 4). Because Wisconsin Gas's plan does not include an earnings sharing mechanism, shareholders would absorb all variation in earnings while the incentive ratemaking plan is in effect. Figure 4 shows that there is considerable variation in the way utilities propose to construct earnings sharing mechanisms.[15] Each of the five utilities is fully at risk when earnings initially fall below the benchmark. Further, the four utilities that have explicit earnings sharing mechanisms have identified floor earnings at which they either receive automatic rate relief or are allowed to file for suspension of the incentive ratemaking plan. Such floors or suspensions are denoted with an "R" in Figure 4. Two of the utilities with earnings sharing mechanisms (PG&E and BUG) have mechanisms that would make ratepayers automatically share in losses before the floor earnings are reached. On the upside, all four utilities with earnings sharing mechanisms have ratepayers share in some of the earnings, either immediately, as in the case of NJNG, or after

14 In contrast to the efficiency loss potential argued here, Gasmi et al. (1994), using simulated data on regulated firms, argue that there is little or no loss in total welfare as a result of earnings sharing mechanisms and that earnings sharing mechanisms increase the consumer's share of total welfare gains.

15 SDG&E's proposed earnings sharing mechanism is defined in terms of return on ratebase. Figure 4 restates SDG&E's mechanism in terms of ROE assuming that debt costs are fixed and the company's debt-to-equity ratio is 1.0.

a dead band is exceeded, as in the cases of PG&E, BUG, and SDG&E. Two plans, PG&E and SDG&E, have identified earnings levels at which either earnings are capped or the PBR is reviewed.

Figure 4. Comparison of PBR Earnings Sharing Mechanisms



Note: SDG&E's sharing mechanism based on ROR is shown on an ROE basis assuming a debt-to-equity ratio of 1.0.

Except for PG&E's plan, all of the base rate incentive plans rely on status quo mechanisms to determine the benchmark return. For NJNG and Wisconsin Gas, authorized return on equity (ROE) is set in the rate case and both utilities propose using the most recently adopted return number for their incentive plan. For BUG and SDG&E, cost of capital is determined in generic (multi-utility) cost of capital proceedings and that would be the source of the benchmark return.[16] PG&E proposes to take itself out of California's annual generic cost-of-capital proceeding and to index its ROE to 30-year treasury bond yields plus 465 basis points.

Off Ramps and Z-Factors: More Ways to Mitigate Risk

All PBR plans must address situations where unexpected costs or revenue impacts occur that challenge the viability of the PBR plan. As noted in Equations 2 and 3, price and revenue index formulas include a "Z" factor that allows for costs that are not otherwise reflected in the PBR mechanism. "Off ramps" are another way to mitigate for these unexpected costs, in this case by modifying or suspending the PBR mechanism. In the previous section it was shown that four of the five base rate plans contain earnings sharing mechanisms tied to some sort of earnings cap or suspension mechanism. These mechanisms may be thought of as "earnings-driven" off ramps. The other way that cost uncertainty is addressed is to simply exclude certain critical or uncertain cost items from the PBR mechanism. Examples of such exclusions are system integrity costs (NJNG) and DSM program costs (all plans except Wisconsin Gas's). These earnings-driven off ramps and exclusions appear to be the primary ways that risk is addressed. However, even with these significant risk mitigation measures in place, three base-rate plans included additional Z factors or other types of off ramps. PG&E's plan addressed Z factors the most explicitly and generically. Their plan would allow for costs that were (1) not otherwise reflected in the inflation, customer growth, and productivity components of its base-rate indices, (2) are outside of the company's control, and (3) are in excess of $50 million or are incurred as a result of a natural disaster (PG&E 1994, pp. 2-11). Wisconsin gas, which has no earnings-driven off ramp, identified four "reopeners:" safety, interest rate fluctuations, generic orders or accounting letters affecting margin, and extraordinary events (Wisconsin Gas 1993, pp. 24). NJNG also indicated that certain regulatory or accounting changes that affect company margin should be considered Z factors (NJNG 1993, pp. 30).

4.3 Procurement Rate Design Issues

Broad Procurement Incentives: Feasible, But Have Yet to be Tested Outside of California

The adoption of procurement mechanisms for two California utilities is an indication of their feasibility. It remains to be seen, however, whether similar incentive mechanism will be adopted for gas utilities in other parts of the country, especially gas utilities in the colder Northeast and Midwest states. Concerns over physical reliability and price volatility appear to make utilities in these regions reluctant to depend on short-term contracts. Long-term contracts pose two problems for utilities subject to broad procurement incentives. First, long-term contracts, especially ones with the volume flexibility required by cold-climate LDCs, often contain price premiums over short-term contracts and such premiums are currently

[16] SDG&E's proposal indicates an intention to move away from annual cost-of-capital proceedings, but no specific alternative is included.

difficult to incorporate into external benchmarks. Second, the terms of the California procurement incentive mechanisms (two and three years) raise uncertainty over the regulatory treatment of any long-term contracts entered into during the incentive plan but that extend beyond the plan. SoCal and SDG&E have avoided these problems by building supply portfolios that rely heavily on contracts with durations of less than 2-3 years. (SoCal does have a certain number of long-term contracts but they are excluded from the procurement incentive mechanism.) Since early evidence indicates SoCal and SDG&E are beating the benchmarks, it appears that the utilities are not paying any premiums over short-term market prices.

It is unlikely that broad procurement incentives will be adopted outside of California until changes in the incentive mechanisms and changes in the gas supply market place are made. Procurement incentive mechanisms may be modified to accommodate longer-term contracts by extending the term of the incentive mechanism and by increasing the tolerance band (no-risk zone) above the market benchmark. Tolerance bands decrease the incentive power of the mechanism but allow for full recovery of premiums over market prices perceived to be necessary for supply reliability. Regardless of incentive design changes, gas markets appear to be evolving in ways that will make market-based benchmarks more representative of LDC procurement costs. Developments in gas supply markets may eventually make physical reliability separable from contract term (Goldman et al. 1993). The development of unbundled storage, capacity release markets, the futures market, and other forms of financial gas contracting all provide ways to mitigate price risk and maintain physical reliability without relying on long-term contracts.

Targeted Procurement Incentives: A Positive Role Given the Regulatory Status Quo

Economists are generally skeptical of targeted incentive mechanisms. Once financial incentives are attached to a particular cost or throughput item, the utility has an incentive to improve performance in that specific area at the expense of performance in other important areas. During the 1970s and 1980s, many electric utilities took on incentive mechanisms that targeted fuel and purchased power costs or power plant performance. The empirical evidence of benefits from such measures is weak (Berg and Jeong 1991; Graniere et al. 1993). There have been no empirical studies on the performance of targeted procurement incentives in the gas industry, in part because they have not been adopted as widely as they have been in electric industry.

The sample of gas utility incentive mechanisms includes two targeted procurement incentives: NJNG's and MichCon's proposals to share the trading gains and losses from participating in the futures market. MichCon's proposal is described further here. In its most recent PGA-like proceeding,[17] MichCon proposed a two-year trial experiment in which it would be allowed

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[17] MichCon is subject to an annual gas cost recovery (GCR) proceeding, which includes a forecast phase for estimating future gas costs, and a retrospective review of past purchases. Actual gas costs are passed through to

to take up to a $20 million position in the futures market.[18] In its testimony, MichCon claimed that 90 percent of its gas portfolio is effectively indexed to spot prices (Wolter 1993a). The only way to reduce this market price risk would be for MichCon to recontract its portfolio or to participate in futures or other financial markets to hedge against this risk.

Initially, MichCon did not propose to share gains or losses from financial hedging. In rebuttal testimony, the utility agreed to a share gains and losses in response to a similar proposal made by a Michigan PSC staff witness (Wolter 1993b). The PSC staff witness was concerned that the futures market can be volatile and that the utility should only be allowed to participate in it if MichCon is put at risk for at least some of the dollars at stake. In response to this concern, MichCon proposed to share trading gains and losses between ratepayers and shareholders. The Michigan PSC adopted a modified version of MichCon's proposal. In it, all gains are shared equally. Losses are also shared equally up to $4 million/year and losses greater than that are borne by shareholders.

From a theoretical standpoint, it would clearly be better to avoid targeted procurement incentive mechanisms and, instead, adopt broader procurement incentive mechanisms (like SoCal's or SDG&E's) or to fully or partially eliminate a utility's PGA. Certainly, a targeted incentive mechanism creates the potential for "perverse" incentives. Given that all other gas costs are subject to PGA-like pass throughs, MichCon's incentive mechanism may lead it to participate in the futures market rather than recontract its existing market-sensitive contracts, even if recontracting would lower costs or better mitigate price risk. These potential losses, however, must be weighed against the benefits of the incentive mechanism: it allows the utility to participate in a new financial market that it would likely avoid absent some form of regulatory pre-approval. Further, it is not unreasonable for the regulatory commission to make risk sharing a condition of pre-approval. Thus, if more radical changes to PGA mechanisms are not feasible, it is reasonable to consider targeted procurement incentive mechanisms.

4.4 Incorporating Nonprice or Nondollar Goals: Service Quality and DSM

Service Quality Incentives: A Popular Supplemental Incentive Mechanism

Ratemaking incentive mechanisms discussed so far focus on the cost or price of metered service; such measures do not capture possible quality changes that could occur under the mechanisms. A common concern with PBR is that it increases the financial incentive of the utility to degrade nonprice performance. Utility performance not reflected in prices or costs can include reliability, customer or employee safety, the responsiveness of customer service departments, commitment to universal service, commitment to social programs, or overall

customers, subject to the retrospective review.

18 A *position* is the dollar value of any futures contracts that have been purchased.

customer satisfaction. Concern over quality impacts is commonly raised in conjunction with proposals for base rate incentive mechanisms. This is because base rates recover costs that cover programs that maintain or enhance service quality. Service quality incentive mechanisms are a way to mitigate potential quality impacts under PBR.

In the sample incentive plans, NMGas's unit cost index and all of the base rate incentive plans, except Wisconsin Gas's, are proposed in conjunction with a service quality incentive mechanism (Table 4).[19] Table 4 shows that there is a wide range in approaches to service quality indices. PG&E and SDG&E's service quality indices rely heavily on a customer satisfaction survey; NMGas, BUG, and NJNG propose to use surveys in conjunction with measured company performance in various areas. In terms of the dollars at stake, the proposed maximum annual incentive payments range from 20 to 53 basis points on ROE.

Table 4. Gas Service Quality Index Incentive Mechanisms

	Utility				
Features	BUG	NJNG	PG&E	SDG&E	NMPC
Total No. of Indicators used in Gas Service Quality Index	22	5	1	2	6
Maximum Annual Incentive Payment (basis points ROE)	50	25	53†	34†	20†
Service Quality Index Includes:					
Customer Survey(s)	X	X	X	X	X
PUC complaint rate	X	X			X
Time to respond to telephone calls or letters	X	X			X
Meter reading/billing accuracy	X	X			X
Time to respond to emergency calls		X			
Customer outreach & education	X				X
Employee Safety				X	

Note: PG&E, SDG&E, and NMPC's service quality indices include measures that are affected by both performance in the electric and gas departments.

† Maximum incentive for company is set in terms of dollars per year. This maximum incentive is converted to basis points using recent estimates of company net plant and an assumed debt-to-equity ratio of 1.0.

19 While the maintenance of service quality was a stated goal in its rate indexing proposal, Wisconsin Gas did not propose an explicit service quality index.

None of the service quality indices use reliability or customer safety as a measure. While these factors are obviously a concern to utilities and regulators, they appear to be absent from the indices for two reasons. First, current levels of gas utility customer safety and firm-customer reliability are relatively high, so that it would be difficult to establish performance indicators that would not be highly volatile and would still give the utility a reasonable chance of outperforming. Second, because of the high cost of restoring service and the high civil liability risk associated with outages and accidents, high safety and reliability are already paramount goals to gas utility managers and they are unlikely to degrade performance in these areas even if PBR increases the financial incentives of doing so.

Demand Side Management: Rate Indexing Can Exacerbate Disincentives for Utility Participation

Although not as common as with electric utilities, many gas utilities in the U.S. sponsor demand-side management (DSM) programs. Seventeen state PUCs mandate some form of gas DSM planning or gas integrated resource planning (IRP) (GRI 1994). DSM planning or IRP can lead to increased utility sponsorship of DSM programs. DSM for gas utilities can include efficiency programs that reduce customer demand (conservation programs), load management programs that emphasize the shifting of customer loads, and fuel substitution programs that usually promote load growth. Given the concurrent interests of gas LDCs in the areas of DSM program planning and PBR, a natural question is whether they are compatible.

The cost of a DSM program to a utility comes in two forms. The first is the DSM program costs, which consists of audit costs, incentive payments, measurement and evaluation expenses, and utility administration costs. The second is the net lost revenues of the program, which is the revenue impact of the DSM program net of the avoided cost benefits and is commonly negative for conservation DSM programs.

Under traditional ratemaking it often the case that a utility has a financial incentive to underspend its conservation DSM budget because it lowers a utility's program costs and minimizes the impact of net lost revenues.[20] There are several ways to counteract these financial disincentives to pursue DSM including audits of utility spending and performance, escrow or balancing account protection on DSM program costs, net lost revenue adjustment mechanisms, sales decoupling mechanisms, and positive shareholder incentives for exemplary utility DSM performance.[21] Conversely, DSM programs that build load, especially off-peak

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20 This assumes that avoided nongas costs are below marginal base-rate revenues, which is often the case for U.S. LDCs.

21 For a detailed discussion of various incentives for utility-sponsored DSM programs, see Nadel (1992) and Goldman et al. (1993).

load, will tend to bring a positive contribution to margin and carry a positive financial incentive. While gas utility DSM programs are often a mix of conservation and load building programs, it is common to mitigate the financial disincentives of conservation DSM programs in some manner.

The area of greatest conflict between incentive ratemaking and utility-sponsored conservation DSM lies with base-rate indexing mechanisms. The conflict exists for three reasons. First, rate indexing mechanisms may be proposed in conjunction with proposals to eliminate any existing mechanisms that protect recovery of DSM program costs. Second, and more importantly, rate indexes cannot coexist with net lost revenue adjustment mechanisms or sales balancing accounts. Third, the longer terms associated with incentive ratemaking plans results in utilities absorbing net lost revenues for longer periods of time.

Revenue indexing mechanisms, in contrast, can preserve or improve incentives for utility participation in conservation DSM programs. Although earnings are not guaranteed under base-rate revenue indices, authorized base-rate revenues are relatively certain and are less affected by sales impacts from DSM programs. DSM programs do not affect revenues because base-rate revenue index mechanisms, by definition, require either frequent updating of sales data (as is the case for BUG) or a sales balancing account (as is the case for SDG&E and PG&E).

Although rate indexing is less compatible with utility-sponsored DSM than revenue indexing, Wisconsin Gas's experience demonstrates that is its possible to preserve utility-sponsored DSM programs in a rate indexing mechanism. Wisconsin Gas has a history of sponsoring DSM programs (including conservation programs) and the cost of such programs has historically been expensed using escrow accounting.[22] Wisconsin Gas proposed to end escrow accounting and, although it incorporated DSM program costs and a certain amount of lost revenues into its initial rates, it proposed to make the entire base rate (including the DSM rate component) subject to the same index. Such indexing will increase its financial incentive to increase rather than decrease sales. Wisconsin PSC staff raised concerns in testimony that a rate index and the elimination of escrow accounting would give utility an incentive to underspend its DSM budget and, thereby, degrade its DSM performance (Kaul 1993). In rebuttal testimony, Wisconsin Gas still argued for the elimination of escrow accounting, but indicated its commitment to meet DSM performance targets, and agreed to reconsider a return to escrow accounting of DSM program costs if Wisconsin Gas fails to meet its performance targets for two consecutive years.

22 Escrow accounting assures full recovery of prudently-incurred program costs. Forecasted DSM expenses are included in rates but the escrow account allows for future rates to be adjusted if actual DSM expenditures are above or below test-year levels.

5 Summary of Observations: The Potential Benefits and Pitfalls of PBR

Ideally, the benefits of PBR should be estimated empirically and, as more gas utility incentive plans are proposed and adopted, it will be possible to begin to do this. Until then, one can only make observations and speculations based on the limited data collected from the plans included in this study.

The following approach is taken to summarize the observations made in this report. First the potential benefits of PBR, originally discussed in Section 2.3, are revisited and results that may be considered supportive of these purported benefits are summarized. Second, potential pitfalls of PBR are identified and, in a fashion similar to the benefits subsection, any evidence that supports these claims is summarized. As was noted earlier, PBR is a new regulatory paradigm that is not without potential pitfalls and it is instructive to review them in addition to the potential benefits.

5.1 Benefits

In Section 2.3, the potential benefits of PBR were organized into four types: improved resource efficiency, improved allocative efficiency, improved ease of introduction of new services, and reduced regulatory and administrative costs. We consider each potential benefit in turn.

Resource Efficiency. Resource efficiency is improved when a utility provides a level of goods and services for less cost. As was shown in Figure 2, only about 21 percent of costs are in the category that the LDC can control the most--nonfuel O&M and plant expenditures. In these base-rate cost categories, Wisconsin Gas, SDG&E, and PG&E have the most powerful plans; NJNG and BUG's plans are noticeably weaker. Without results it is difficult to say how these plans will actually affect utility costs. At best, the productivity factors of the three more powerful base rate plans can be pointed to: they are all positive and, at least in the case of Wisconsin Gas, they include a "push" above historical levels. It is important to note, however, that positive productivity factors do not by themselves indicate progress. For example, historical LDC base rates for residential and commercial service grew at 4.9 and 2.6 percent/year, respectively, for the period 1982 to 1992.[23] In contrast, the consumer price index grew at 3.8%/year over the same period. These data indicate rates, for at least commercial customers, have fallen relative to inflation under COS/ROR regulation, so one must use caution before one declares a PBR rate index or revenue index to be an improvement.

[23] Base rates calculated using data from AGA (1992).

With respect to procurement incentive mechanisms, the initial results appear promising. As noted in Section 3.2, one utility, SDG&E, has beat its market-based benchmark by several percentage points.

Resource efficiency may also be evaluated in terms of its ability to institutionalize regulatory lag. Here the plans to show an improvement over the status quo. The shift in base rate plans is from 1-3 to 3-6 years (Figure 3). The broad procurement plans go from no regulatory lag (zero years) to 2-3 years. So long as earnings sharing mechanisms do not overly dilute the incentive properties of the longer plan terms, these plans increase the incentives for improved resource efficiency.

Allocative Efficiency. Three of the sample PBR proposals, BUG's, NJNG's, and Wisconsin Gas', included increased pricing flexibility in their PBR proposal. Pricing flexibility appears to be a trend that will likely continue in the industry with or without PBR, but it is reasonable to believe that PBR facilitates pricing flexibility because it reduces customer uncertainty over who is allocated the shortfalls created by discounting.

Introduction of New Services. For the same reasons that PBR facilitates pricing flexibility, PBR should facilitate the introduction of new services. Gas utilities have, in other forums, proposed new services such as targeted gas portfolios, gas tracking services, customer cogeneration, and utility-provided alternative fuel services. The plans reviewed herein were, however, silent in regard to new services. It is possible that once the PBRs are in place, the utilities will return to the regulator for approval of mechanisms that allow for streamlined introduction of new services.

Administrative and Regulatory Costs. The sample plans indicate that the ratemaking cycle is lengthened under the proposed PBR plans. This change alone reduces regulatory costs. In addition to the reduction in the number of rate cases, reasonableness reviews are eliminated under the two broad procurement plans from California. California has a long history of contentious reasonableness review proceedings, so their elimination, if sustained, is a tangible benefit. The impact of increased monitoring and evaluation costs will partially offset these benefits, however, and is discussed further in the pitfalls section, below.

5.2 Pitfalls

PBR for energy utilities is not universally accepted as a superior mode of regulation to COS/ROR regulation. Even its supporters would agree that there are several competing PBR mechanisms and that few have been adequately tested. Pitfalls that have been raised are identified below and any observations from the plan review that could be considered supportive of the pitfall is also presented.

Questionable efficiency benefits. The plan review indicates that the ability of PBR mechanisms to truly break out of the COS/ROR mold is limited. Terms can be extended, but rate cases cannot be eliminated entirely. Increased profits can dangled as a lure but, if actual profits are perceived to be too high or low, the viability of the PBR mechanism will be threatened. An argument can be made that the total amount of costs that can be reduced by a PBR is fundamentally limited. The fraction of costs that a gas utility controls the most, nonfuel O&M and capital additions, is only 21 percent of total costs on average. Purchased gas costs are a larger expense, accounting for 60 percent of industry revenues, but the ability of utility management to control them is more limited. If, for example, a PBR was found to decrease controllable on-system costs by 6 percent (achieved, say, over a multi-year period) and reduced procurement costs by 2 percent, the average rate impact would only be 2.5 percent. Some question whether any PBR mechanism really adds adequate risk to match the increased opportunity for return. That is, with a limited opportunity for improved productivity, opportunities for improved profits can only be achieved through lax inflation and productivity targets.

Undesirable equity impacts. PBR can affect utility-customer and inter-customer equity in at least three ways. First, PBR mechanisms rely on external measures of cost. Although such external measures are necessary to provide incentives for superior performance, they can lead to higher profits that may be perceived to be unfair. Second, PBR mechanisms often have terms longer than the status quo. These longer terms can harm parties who are unhappy with their existing rates because the PBR provides fewer rate cases in which to litigate. Further, given the increased stakes of rate cases, customers may become the victim of gaming of the initial rates or of the PBR index mechanism. Third, if it allows for pricing flexibility, a PBR will likely lead to a reduction in relative rates for customers or customer classes with the most alternatives. It is well known that a monopolist that serves multiple customer classes subject to a price cap with downward pricing flexibility will move towards inverse-elasticity, or Ramsey, prices (Lyon 1994, pp. 11). While Ramsey pricing has desirable efficiency properties and could be implemented in a COS/ROR framework, it has been unpopular with state commissions because the notion of raising relative rates of customers with the least alternatives is often considered unfair.

Questionable administrative cost savings. Anecdotal evidence from state experience with telecommunications and energy utility PBR indicates that the reduction in administrative costs of from less-frequent rate cases has been offset in part by an increase in monitoring and evaluation costs.[24] Further, pricing flexibility, if allowed, may require that complaint cases regarding unfair competition be held more frequently.

The status quo already contains a duty to perform. Some regulators view their control over energy utilities primarily in terms of the legal framework in which economic regulation operates. Most states define gas and electric utilities as public utilities that are conferred monopoly status in return for price regulation and an obligation to serve. Monopoly public

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24 See for example the monitoring and evaluation program proposed in SDG&E et al. (1993). Similar programs have been set up as part of California's telecommunication PBRs.

utilities are already supposed to deliver goods and services at an acceptable level of quality and reliability for the lowest possible cost (Hanaway 1994). Additional financial incentives that are a part of PBR mechanisms are unnecessary and reduce the importance of the existing incentive mechanisms inherent in COS/ROR. These existing incentives include regulatory lag, prudence tests, and the threat of revocation of the monopoly franchise.

Inability to incorporate environmental, social, and other nonprice goals. Because PBR increases the incentive to improve performance as measured by the chosen benchmark or index, it will presumably divert resources and attention away from other goals. Service quality and reliability are often cited as being at risk under PBR, but explicit service quality incentives and litigation risk appears to adjust for these quality attributes. Less resolved is a gas utility's performance in the areas of demand-side management, environmental management, and low-income programs. Gas LDCs will presumably have less interest in these areas if the PBR does not explicitly account for these programs. A total social cost index can be created that includes the estimated value of these "nondollar" goals although no gas utility has pursued it. Targeted supplemental incentives have been added, particularly for demand side management. Finally, the costs and performance goals of these programs can be separated from the PBR and subject to traditional regulation. It is likely, however, that PBR will continue to create friction with between utility rate or revenue goals and these nondollar goals.

5.3 Conclusions

Ongoing industry restructuring is introducing greater competition to the gas distribution industry. FERC's current policies, including those expressed in its Order 636, have resulted in increased unbundling of upstream services, increased LDC responsibility for procurement decisions on behalf of their sales customers, and increased opportunities for customers to bypass the LDC's procurement and, possibly, transportation services. As a result of these changes in federal policy and other industry developments, LDCs are actively restructuring their holdings of upstream transportation and storage facilities, re-evaluating their on-system costs, and are re-evaluating their procurement portfolios. State PUCs are also re-evaluating their regulations in an effort to maximize system utilization, lower LDC rates, maintain reliability for firm customers, and lower regulatory costs. While the dust from restructuring has not settled, it appears that LDCs will remain secure in their monopoly status, at least for the on-system transportation and distribution services for most customers and bundled transportation/distribution/procurement services for core customers (Hatcher and Tussing 1992). PBR holds promise as a way for regulators and gas utilities to better achieve their regulatory goals in the current natural gas industry because it puts greater attention on performance and is more compatible with a utility industry that faces competition in some business segments. The challenge for regulators in the future will be to improve regulation without undergoing a costly transition. Such a transition will be facilitated by a critical review of a regulator's goals and objectives. How important, for example, are nonprice goals given that PBR puts increased financial pressure to lower rates and/or costs? If nonprice goals are important, how can they be incorporated into the PBR while maintaining the fundamental

PBR strategy of relying on external benchmarks and avoiding micromanagement? Finally, a transition to PBR will be facilitated by an understanding of the strengths and weaknesses of PBRs that have already been adopted by early-adopting states and utilities. This report, by reviewing nine such plans, makes one step in facilitating this transition.

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