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TRANSITION-COST RECOVERY AND TRUEUP MECHANISMS

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SUMMARY

Designing a workable and policy-responsive cost-recovery and trueup mechanism may be the key unresolved issue related to the transition costs (TCs) facing U.S. electric utilities. This report first discusses the general issues associated with the design and implementation of such mechanisms. It then presents the results of quantitative analyses that show how seven mechanisms perform against six public-policy objectives. The seven mechanisms are:

1. Fixed TC recovery: The utility receives 100% of the predetermined, regulator-approved TC. In the present analysis, this amount is set equal to the base-case (expected) TC estimate.

2. Full TC recovery: The amount of TC the utility receives is adjusted so that it equals 100% of the allowed TC for the situation that actually occurs. This mechanism adjusts the TC amount based on changes in both exogenous factors (i.e., those outside the utility's control, such as regional economic growth and fuel prices) and endogenous factors (i.e., those under the utility's control, such as heat rates at its generating units).

3. Full TC recovery for exogenous factors only: The utility receives 100% of the allowed TC for the exogenous situation that actually occurs. Unlike Mechanism 2, this one does not adjust for changes in endogenous factors.

4. Fixed retail price: The amount of money the utility receives is determined by the requirement that the sum of the market price of power plus the transition charge is equal to a predetermined retail price for bulk-power generation services.

5. Retail-price reduction: The amount of money the utility receives is determined by the requirement that the sum of the market price of power plus the transition charge is equal to some fraction (less than one) of the expected (base-case) value. Mechanism 4 is a special case of this one.

6. Cost sharing: The utility receives a fixed percentage, between 0 and 100, of the allowed recovery for the exogenous situation that actually occurs (Mechanism 3) plus all of the cost-reduction it achieves. Mechanism 3 is a special case of this one, with the fixed percentage set equal to 100%.

7. Performance-based rate: The utility receives 100% of the allowed TC based on the exogenous situation that actually occurs (Mechanism 3) minus an adjustment based on a predetermined reduction in utility generation costs.

We tested these seven mechanisms against six objectives related to customer interests (customers should face market-induced price changes, and retail prices should not exceed today's regulated prices), utility-shareholder interests (utility earnings should respond to market forces as do the earnings for other suppliers, and the utility should face incentives to reduce generation-related costs), risk sharing (customers should neither over- nor under-pay TCs), and administrative simplicity. These analyses use synthetic data created for a hypothetical utility in a larger electrical region.

Table S-1 summarizes our interpretation of these analyses. State regulators might focus on the two mechanisms that provide clear incentives to the utility to cut generation-related costs and a clear "cost-sharing" benefit to retail customers. Mechanism 6 would allow the utility to recover a fixed percentage of the actual transition costs associated with changes in exogenous factors (such as changes in competition-induced regional electricity prices). Mechanism 7 would allow the utility to recover 100% of the actual transition costs associated with changes in exogenous factors less a fixed amount to reflect the state regulator's judgement on the amount of money the utility should be able to save each year.

Table S-1. Comparison of alternative cost-recovery and trueup mechanisms[a]

Objective/mechanism	Fixed recovery (expected value)	100% recovery for exogenous and endogenous factors	100% recovery for exogenous factors only	Fixed retail price (expected value)	5% price cut	Utility gets 100% of its cost reductions	
						+97% of recovery for exogenous factors	–$10 million cost adjustment
Simple to administer	Y	N	Y	Y	Y	Y	Y
Retail prices							
- Do not increase from base case	Y	Y	y	y	Y	Y	Y
- Move with market prices	Y	n	y	N	N	y	y
Utility earnings							
- Respond to market forces	Y	Y	y	y	-	-	-
- Respond to utility cost reductions	Y	N	Y	Y	Y	Y	Y
Little risk of over- or under-recovery	n	n	Y	Y	N	y	y

[a]A "Y" means that the mechanism consistently performs well on this objective, a "y" means that the mechanism generally performs well, a "-" means that the mechanism's performance is neutral or mixed, an "n" means that the mechanism generally performs poorly, and an "N" means that the mechanism consistently performs poorly.

LIST OF ACRONYMS

MTC	Market transition charge (usually in ¢/kWh)
ORCED	Oak Ridge Competitive Electricity Dispatch model
O&M	Operations and maintenance
NUG	Nonutility generator
PUC	Public utilities commission
TC	Transition cost (usually in million $)

INTRODUCTION

State legislatures and regulators face five key issues associated with transition costs (TCs):

- Calculation of TCs, in particular the use of market mechanisms vs the use of administrative methods;
- Magnitude of potential TC amounts;
- Methods to mitigate (offset) these costs;
- Allocation of the remaining costs among different groups, including utility shareholders, electricity consumers, taxpayers, and independent power producers; and
- Cost-recovery and trueup mechanisms. Cost recovery refers to the method (e.g., through an energy charge vs a monthly customer charge) used to collect from customers the TC amount that the state regulator has determined to be appropriate. Trueup refers to the method used to determine, from year to year, what that amount should be.

This last issue may be *the* key unresolved TC dilemma facing state policymakers. At a philosophical level, policymakers face two extreme choices. The first calls for considerable effort and diligence to develop an *a priori* and accurate number for *the* transition-cost amount. Exactly how much money will this utility lose in a fully competitive electricity market because of its generating units, its power-purchase and fuel-supply contracts, and its regulatory assets? Because the TC estimate depends on the difference between the utility's embedded costs and market prices, the estimate is very sensitive to even small changes in either factor.

The second choice focuses on the design of cost-recovery and trueup mechanisms to ensure that, on an ongoing basis, the utility recovers those costs to which it is entitled, no more and no less. In this case, the up-front estimate of the TC amount is less important than in the first case. On the other hand, with this choice, the design of an appropriate mechanism is critically important.

This report focuses on the second choice.[*] The rest of this chapter discusses various objectives for these cost-recovery and trueup mechanisms. Chapter 2 identifies candidate mechanisms and qualitatively discusses their performance against the objectives. Chapter 3

[*]See Baxter, Hirst, and Hadley (1997) for a comprehensive review of TC issues.

presents quantitative results obtained with the Oak Ridge Competitive Electricity Dispatch (ORCED) model. These results show how different mechanisms perform relative to specific customer and utility objectives for a variety of situations involving changes in the bulk-power market and/or changes in the utility's generation-portfolio costs and performance. Chapter 4 summarizes the key findings from this analysis. Chapter 5 explains how these specific mechanisms can be implemented. Chapter 6 presents our conclusions and recommendations to public utility commissions (PUCs) on which mechanisms are worth considering for adoption.

The Texas PUC (1997) suggests that recovery mechanisms be assessed for their effects on (1) rates, (2) incentives to utilities to cut costs, (3) effects on competitive electricity markets, and (4) administrative simplicity. Madian (1997) suggests that cost-recovery mechanisms should meet three goals:

- Enhance competition and minimize market power (he argues for use of TC recovery as a bargaining chip with utilities; e.g., to get them to sell some of their generation);

- Reduce costs for consumers and producers; and

- Value appropriately and mitigate the costs of uneconomical assets.

Tye and Graves (1996), in a study prepared for the Edison Electric Institute, argue that TC recovery need not interfere with competitive generation markets. They suggest that TC-recovery mechanisms should meet the following criteria: "reliable cost recovery, competitive neutrality, allocational efficiency, fairness of incidence on customers, transparency and predictability, administrative simplicity, objectivity (few concerns about biases or distortions in the estimates), automatic termination (sunsetting), and incentives to mitigate."

A report prepared for the Arizona Corporation Commission (1997) suggests that a recovery mechanism should be "reasonable and timely; be fair, equitable, and nondiscriminatory; promote economic efficiency; and provide reasonable opportunity for affected utilities to recover stranded costs." The report also mentions trueup mechanisms:

> [Commission] staff strongly supports the concept of a periodic true-up as being necessary to assure that electric restructuring in Arizona is carried out in a manner that protects the public interest. Such a revisiting does not have to guarantee a dollar-for-dollar recovery, but at a minimum, it should enable prospective adjustments of the stranded cost charge to reflect major uncontrollable variables, particularly the market price for power.

The New Jersey Board of Public Utilities (1997), in its report on restructuring, noted:

> We are particularly concerned that short-term market price indexes proposed to administratively determine stranded costs for purposes of setting the MTC [market transition charge] may understate the true market value of a generating

> asset over its full life. We will determine at the conclusion of said filings [the July 15, 1997, filings that the Board ordered the utilities to prepare on unbundling, stranded costs, and restructuring] whether divestiture is necessary to perform an appropriate market valuation.

Because of its concern that *a priori* estimates of TC amounts are likely to be in error, the Board ordered each utility, in its TC filing, to address trueup mechanisms:

> Absent a divestiture of generating assets by the utilities, in order to assess currently the magnitude of potentially stranded cost, it is necessary to estimate the market value of utility production. As the market develops and matures over time, it is likely that the precision of stranded cost quantification will improve. The market transition charge should therefore be subject to true-up, to reflect the realized market value of utility production through the transition period, either via market sales of power or from asset divestiture.

Unfortunately, none of these documents discussed the feasibility of meeting all their objectives simultaneously. Nor did they suggest specific mechanisms and how they might fare in meeting these objectives. In addition to this limited review of the literature, we contacted people at several state regulatory agencies. These discussions with staff at the Massachusetts, Missouri, New York, Pennsylvania, and Vermont commissions as well as at the National Regulatory Research Institute failed to uncover specific, workable proposals for cost-recovery and trueup mechanisms.

Equity and efficiency are two key criteria to consider in assessing alternative mechanisms. Equity refers to the distributional consequences of a recovery mechanism. The most controversial equity issue concerns the share of TC recovery to which a utility is entitled; see Clemente (1997) and Rose (1996) for opposing views on this topic. A recovery mechanism should allocate costs to parties in relation to their past obligations and expectations. As an example, a per-customer recovery charge levied without regard to the historic electricity use for each customer class (or each customer) would not pass this test.

Consider, as an example, a recovery mechanism that collects TCs from all customers on a ¢/kWh basis, with the charge assessed on all electricity that flows through the utility's distribution system. A large industrial customer that installed a behind-the-fence cogeneration facility would evade much of its TC responsibility. On the other hand, a $/customer-month charge would prevent this problem. However, a fixed monthly charge, even if it differed across rate classes, would lead to intraclass inequities because of precompetition differences among customers within a class in their use of electricity.

Efficiency refers to the resource-allocation and market-operation implications of a recovery mechanism. A cost-recovery mechanism should not distort competition by affecting consumer choice among competing suppliers. Nor should a mechanism encourage high-cost generators to operate instead of low-cost units. A mechanism should not act as a barrier to entry for new suppliers (e.g., by making it profitable for an existing supplier to engage in predatory pricing, such that it underprices a new entrant that would otherwise have lower costs). A mechanism should encourage utilities to reduce the amount of TCs as much as possible (e.g., by retiring generating units that are uneconomical to operate and by renegotiating power-purchase and fuel-supply contracts). At a minimum, the mechanism should not allow a utility to recover more than its unavoidable fixed costs (as discussed in Chapter 9 of Baxter, Hirst, and Hadley 1997). Finally, whatever mechanism is chosen should be simple to administer and should reduce the opportunities for litigation.

The analytical results presented in Chapters 3, 4, and 6 treat only one year of what is likely to be a multiyear cost-recovery period. Analysis of TC recovery involves two time periods. The first period is associated with the book lives of the relevant assets (utility-owned generating units) and liabilities (long-term fuel-supply and power-purchase contracts). This analysis of year-to-year TCs should continue until the longest-lived asset is retired or the longest-lived contract expires. As discussed in Chapter 9 of Baxter, Hirst, and Hadley (1997), the utility's embedded cost of generation will decline with time. On the other hand, the market price of power will likely increase from the current short-run marginal cost (based on today's excess capacity) to the long-run cost of new generation (probably a gas-fired, combined-cycle unit). Because these embedded-cost and market-price trends move in opposite directions, TCs will likely become negative at some point. Calculation of the net present value of TCs should account for both the short-term positive costs and the long-term negative costs to provide an accurate estimate of the net cost.

The TC-recovery period is a policy choice, not an analytic determination. A short recovery period hastens the time when the monthly transition charge is eliminated and all generation suppliers operate on a similar basis. On the other hand, the shorter the recovery period, the greater the transition charge. Five years appears to be a typical cost-recovery period.

CANDIDATE MECHANISMS

Regulators have many choices for cost-recovery and trueup mechanisms. These candidates include:

- *Securitization* is the issuance of bonds, for which the state guarantees that customers will pay the interest and principal (Regulatory Assistance Project 1997). Because of this state guarantee, these bonds are low in risk and therefore carry an interest rate lower than that for investment-grade corporate bonds. The utility receives the full bond proceeds when the bonds are issued and then, on behalf of the bondholders, collects interest and principal payments from its customers on a monthly basis. The only reconciliation associated with such bonds occurs if the monthly collections of principal and interest payments do not match those called for in the bonds; that is, the bondholders have a virtually ironclad guarantee of recovering their investment from electricity consumers within the utility's jurisdictional boundaries. (Adjustments to the monthly payments are symmetric. That is, if retail electricity use is higher than expected, the payments are reduced, and vice versa.)

- *Exit fees* require departing customers to make a lump-sum payment (or a periodic stream of payments with the same net present value as the lump-sum payment) to the utility for the TCs associated with that customer's decision to purchase its energy and capacity resources elsewhere. This is the approach that the U.S. Federal Energy Regulatory Commission (1996) uses for recovery of wholesale transition costs.

- An *up-front determination* of the amount of TC that a utility is entitled to recover and a cost-recovery mechanism that ensures that the utility, over time, recovers no more and no less than that predetermined amount. Periodic trueups and balancing accounts could be used to adjust the monthly transition charge that customers pay for changes in load growth and any other factors that affect the amount of money so recovered. Because this approach predetermines the amount of utility recovery, it should be simple to administer.

- *Full (100%) recovery of TCs*, agreement that the utility will recover dollar-for-dollar its actual TCs. This approach requires periodic (e.g., annual) trueups to ensure that the utility recovers its ongoing actual losses. In this case, the utility would recover fully the difference between its embedded costs of generation and the market price of generation. Such a system would provide no incentive to the utility to cut costs and improve productivity.

- *Prior specification of the retail price* for generation services, perhaps capped at the current regulator-approved price or cut by a predetermined percentage. The utility would then be allowed to collect TCs from its customers on the basis of the difference between the set price and its actual, ongoing costs of generation. No trueup is conducted with this approach.

- A *performance-based determination* of allowable generation costs that the utility can recover. This approach is a refinement of the prior mechanism in that it allows for continuing reductions in the price that retail customers pay for generation services. Such a performance-based mechanism could be very simple (e.g., a 2% per year reduction in allowed generation costs). Or it could be very sophisticated, with allowed costs tied to regional fuel prices and the performance of the utility's generators [e.g., unit heat rates and availabilities, and operations and maintenance (O&M) costs tied to indices of industry performance]. Again, no formal trueup is needed here because it would occur automatically, based on the particular mechanism chosen by the PUC.

- An after-the-fact reconciliation of TCs with a *shared-savings mechanism*. In this case, the utility would recover a predetermined percentage of the difference between its embedded costs of generation and the market price of generation. This system provides a clear incentive to the utility to cut costs and improve productivity.

None of these approaches satisfies all the objectives that have been suggested for these cost-recovery and trueup mechanisms. The first three mechanisms (securitization, exit fees, and use of an MTC to recover a predetermined TC amount) all have similar characteristics. Specifically, these methods are simple to administer, primarily because either they involve no trueup or the amount of trueup is simple to determine. On the other hand, these methods provide no direct benefits to customers and may offer no incentive to the utility to cut its future generation costs. As the U.S. Federal Energy Regulatory Commission (1996) noted, "The primary rationale offered in support of a snapshot approach is certainty; the primary rationale offered in support of true-ups is accuracy."

Assurance that the utility will recover 100% of its ongoing transition costs insulates the utility from competitive generation markets and therefore provides no incentive for the utility to improve its productivity. On the other hand, full recovery can be simple to administer, and it provides revenue stability to the utility.

The last three methods listed above can provide productivity incentives to the utility and price reductions to customers. However, these methods are more complicated to design and implement and could lead to litigation every time the method is applied (e.g., the equivalent of an annual rate case). In addition, these methods place the utility at risk for nonrecovery of some of the TC amount.

QUANTITATIVE ANALYSIS

To quantify the ability of different mechanisms to meet the objectives outlined above, we simulated the operations of a hypothetical utility within a larger system of interconnected generating and transmission facilities. We used the ORCED (Oak Ridge Competitive Electricity Dispatch) model to conduct this analysis.* To simplify the analyses and their presentation, we focused on one year of what is almost certain to be a multiyear recovery period.

We ran several cases with ORCED to simulate the effects of exogenous and endogenous changes on the market price of electricity and the utility's transition costs. By exogenous, we mean factors that are outside the direct control of the utility for which we calculate TCs. Exogenous factors include changes in regional loads, fuel prices, and generating capacity. By endogenous, we mean factors that are primarily within the control of the utility. Such factors include generating-unit heat rates, generation fixed O&M costs, retirement of generating units whose revenues do not cover avoidable fixed O&M costs, and renegotiation of nonutility generator (NUG) contracts. We make no effort in this study to assess the feasibility and cost-effectiveness of these utility cost-reduction efforts. Our sole purpose here is to see how such actions, if successful in cutting costs, would affect utility cost recovery and retail electricity prices under different mechanisms.

BASE CASE

We began by creating a utility that faces a substantial TC problem. The utility has 7,200 MW of generating units and NUG contracts. Two of these units are nuclear, with very high fixed costs. In addition, the utility has three NUG contracts, all of which have costs well above market prices. The utility generates about 13% more electricity than its retail customers consume, with the extra energy sold in the regional bulk-power market.

This utility is embedded in a larger region that contains an additional 56,600 MW (for a total of 63,800 MW). The region's peak demand is 54,000 MW, of which 6,000 MW are accounted for by the retail customers of our utility. We assume that there are no transmission losses, costs, or constraints between our utility and the rest of this region.

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*ORCED was developed at Oak Ridge National Laboratory, primarily with funding from the U.S. Environmental Protection Agency. See Appendix A of Hadley and Hirst (1998) for a description of the model.

Under these base-case conditions, the utility's generation resources operate with an overall capacity factor of 59% (higher than the rest of the region's units, which have an overall capacity factor of 53%). The utility's generation revenues for the analysis year total $1,096 million, its variable costs are $832 million, its (avoidable) fixed O&M costs are $246 million, and its capital costs are $359 million. (Capital costs, equivalent to unavoidable fixed costs, include depreciation, income and other taxes, interest payments on bonds, and allowed return on equity.) Thus, the utility loses $342 million, almost as much as its annual capital costs.* Thus, we created a utility with a very serious TC problem, reflected in the substantial difference between the total cost of its generation (3.85¢/kWh) and the market price of power (2.94¢/kWh). Its three NUG contracts lose $178 million a year, its two nuclear units lose $216 million, and ten of its fossil units lose $58 million. This $452-million loss is offset by only $110 million of operating margin from those generators that are economical to operate in this base case.

SCENARIOS

In addition to this base case, we ran 32 simulations testing different combinations of exogenous and endogenous changes. Table 1 shows the key changes simulated.# In addition to the cases shown in Table 1, we ran several combination cases that included both an exogenous factor and an endogenous factor (e.g., regional capacity 5% higher than expected plus utility fixed O&M costs cut 10%); Table 2 lists all the cases run here. The second and third columns of Table 1 show how each change affects the utility's TCs and the market price of power. In almost every case, a change that benefits the utility (e.g., higher regional loads or retirement of high-cost units) increases the market price of power. The reverse is also true. These results suggest that it is difficult to design a TC recovery and trueup system that meets both customer and utility objectives (Fig. 1): as market prices decline (benefitting customers), TCs increase (harming shareholders).

Table 3 summarizes key ORCED results for 7 of the 33 cases analyzed here. Across these cases, bulk-power market prices vary by up to 6%, and utility TCs vary by up to 27%. Retail generation prices vary less than do bulk-power generation prices (0.09 vs 0.21¢/kWh) because the MTC partly offsets changes in market prices.

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*Of this $342 million loss, $147 represents the utility's authorized return *on* equity and −$195 million is net income.

#We could have run more cases to test the effects of changes in different exogenous and endogenous factors (e.g., in system load shape or planned-outage rates). We did not do so because these additional cases would likely have yielded few new insights concerning the effects on the utility and its retail customers of different mechanisms.

Table 1. Effects of various factors on the prerecovery transition costs the utility faces and the market price of power

	Effect on	
	Transition costs	Market price
Exogenous factors[a]		
Regional load 5% higher than expected[b]	-7	2
Regional load 5% lower than expected	9	-3
Regional heat rates 5% higher than expected	-14	4
Regional heat rates 5% lower than expected	13	-4
Regional forced-outage rates 3% higher than expected	-5	1
Regional forced-outage rates 3% lower than expected	8	-3
Region retires 2300 MW of uneconomical units	-3	1
Region adds 2300 MW of new combined-cycle units	9	-3
Endogenous factors[c]		
Make NUGs 2 and 3 dispatchable, guarantee owner's earnings	-7	No change
Cut generating-unit heat rates 5%	-8	No change
Shut down high-O&M-cost units (625 MW)	-13	No change
Cut fixed O&M costs 10%	-3	No change

[a]These exogenous factors do not apply to the utility that is the focus of this analysis; they apply to all the other generating units and loads in the region.

[b]Expected refers to the *a priori*, PUC-approved, administratively determined estimate of allowable transition-cost recovery and MTC.

[c]Changes in the utility's generation costs should have very little effect on bulk-power prices unless the utility's generators are frequently on the margin and therefore determine the spot price. For the four endogenous cases, the maximum change in market price is 0.5%.

The first two rows of Table 3 show the actual and allowed TC that the utility experiences in each case, with the difference equal to unrecovered fixed O&M costs (as discussed below). The market price is the annual average of the time-varying competitive price in the regional bulk-power market. The two retail-sales rows refer to the region as a whole and to the utility's service area (with the latter not necessarily equal to the utility's production because of wholesale trading between the utility and the rest of the region). The utility production costs refer to the total costs normalized by the utility's energy production (shown in row 6). The following three rows show the annual generation revenues, costs, and earnings (the difference between revenues and costs) for the utility, all in millions of dollars. The disallowed TC is equal to the difference between the actual and allowed TCs. The next row shows the savings achieved by the utility's generation-cost-cutting activities. The last two rows show the allowed MTC and the price of generation to retail customers. The MTC is the per-kilowatt-hour payment that customers make to the utility for allowable TCs.

Table 2. Scenarios used to analyze alternative cost-recovery and trueup mechanisms

1.	Base case
	Vary exogenous factors only
2.	Increase regional load 5%; regional load shape unchanged
3.	Decrease regional load 5%; regional load shape unchanged
4.	Increase regional heat rates 5%
5.	Decrease regional heat rates 5%
6.	Increase regional forced-outage rates 3%
7.	Decrease regional forced-outage rates 3%
8.	Decrease regional generating capacity 2300 MW by retiring uneconomical units
9.	Increase regional generating capacity 2300 MW with new combined-cycle units
	Vary endogenous factors only
10.	Make NUGs 2 and 3 dispatchable; guarantee earnings to the NUG owners
11.	Decrease utility heat rates 5%
12.	Retire 625 MW of utility generating units with high O&M costs
13.	Cut utility fixed O&M costs by 10%
	Vary exogenous and endogenous factors
14–17.	Decrease regional heat rates 5%; vary four endogenous factors
18–21.	Increase regional heat rates 5%; vary four endogenous factors
22–27.	Utility retires 625 MW of uneconomical units; vary six exogenous factors
28–33.	Cut utility heat rates 5%; vary six exogenous factors

Actual and allowed TCs can differ if some of a utility's generating units are unable to produce enough revenue to cover both variable costs and fixed O&M costs. Because O&M costs are avoidable (unlike the unit's capital costs, O&M costs can be avoided by shutting down the unit), we assume that the PUC will exclude them from the allowable TC.* For the base case, this utility has $13 million of such avoidable TCs, which are considered disallowed. In our discussions of ORCED outputs, we always consider only allowed TCs.

The value of allowed TCs ranges from $230 to $374 million across the 33 cases, with an average of $307 million. The average value of utility cost reductions for those 24 cases is $41 million, with a range from $16 to $93 million.

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*Specifically, we assume that the PUC will want utility shareholders to face the same kinds of risks and rewards that NUG owners do. That is, all generator owners should be free to make the decisions and bear the consequences of shutting down or continuing to operate generating units in the face of uncertainty over future market prices and, therefore, of generator earnings.

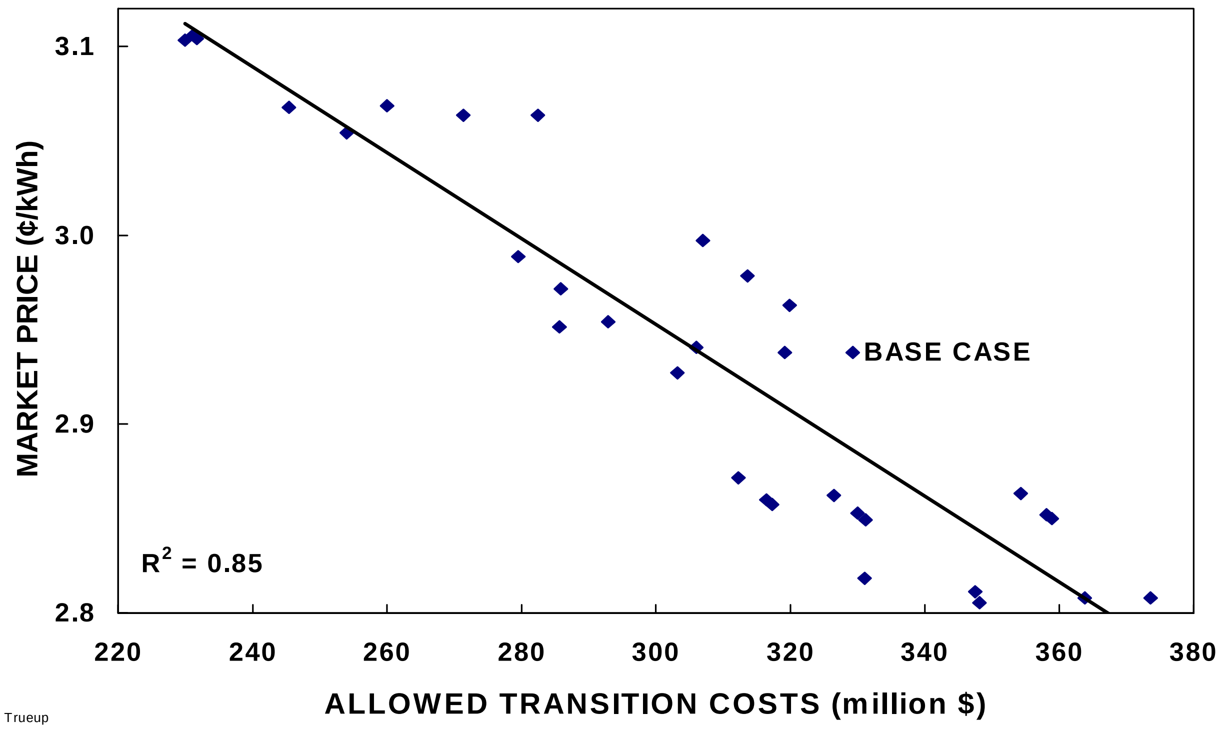

Fig. 1. **Bulk-power market prices as a function of allowed transition costs for 33 cases in which various exogenous and endogenous factors are varied.**

SPECIFIC MECHANISMS AND POLICY OBJECTIVES

We created a separate spreadsheet that uses ORCED results to test the effects of different cost-recovery and trueup mechanisms. Consistent with the discussion in Chapter 2, we analyzed seven specific mechanisms:

1. Fixed TC recovery: The utility receives 100% of the predetermined, PUC-approved TC. In the present analysis, this amount is equal to the base-case (expected) calculation of TCs.*

2. Full TC recovery: The utility receives 100% of the allowed TC for the situation that actually occurs. This mechanism adjusts the TC amount based on changes in both exogenous and endogenous factors. Thus, utility shareholders receive no credit for any generation-cost reductions that the utility achieves.

*Securitization and exit fees are examples of predetermined fixed-cost recovery and, therefore, are not considered separately here. That is, their ability to meet various public-policy objectives is identical to that of the first mechanism analyzed here. Also, this approach could involve recovery of less than 100% of the *a priori* estimate of allowable TCs.

Table 3. ORCED results for a sample of cases used to assess the effects of different transition-cost recovery and trueup mechanisms

		Changes in exogenous factors			Changes in endogenous factors		
	Base (expected)	Regional load +5%	Regional load −5%	Regional heat rates +5%	Utility heat rates −5%	Utility fixed O&M costs −10%	Utility retires high-O&M-cost units (625 MW)
Actual TC, M$	342	318	374	292	315	325	286
Allowed TC, M$	329	307	358	282	303	319	286
Market price, ¢/kWh	2.94	3.00	2.85	3.06	2.93	2.94	2.95
Retail sales, GWh							
Total	297,669	310,899	284,439	297,669	297,669	297,669	297,669
Utility	33,074	33,074	33,074	33,074	33,074	33,074	33,074
Utility production, GWh	37,358	38,496	36,185	39,802	39,657	37,358	35,016
Utility production costs, ¢/kWh							
Variable	2.23	2.24	2.21	2.26	2.18	2.23	2.32
Fixed O&M	0.66	0.64	0.68	0.62	0.62	0.62	0.53
Capital	0.96	0.93	0.99	0.90	0.90	0.96	0.91
Total	3.85	3.82	3.88	3.78	3.71	3.80	3.76
Utility revenue, M$	1096	1151	1030	1214	1,155	1096	1032
Utility costs, M$	1438	1469	1404	1506	1470	1421	1318
Utility earnings, M$	−342	−318	−374	−292	−315	−325	−286
Disallowed TC, M$	13	11	16	9	11	6	0
Utility cost-cutting, M$	0	0	0	0	27	16	56
Allowed MTC, ¢/kWh	1.00	0.93	1.08	0.85	0.92	0.97	0.86
Market price + allowed MTC, ¢/kWh	3.93	3.93	3.93	3.92	3.84	3.90	3.82

3. Full TC recovery for exogenous factors only: The utility receives 100% of the allowed TC for the exogenous situation that actually occurs. Because this mechanism ignores endogenous factors, utility shareholders receive full credit for any generation-cost reductions that the utility achieves.

4. Fixed retail price: The amount of money the utility receives is determined by the requirement that the sum of the market price of power plus the MTC is equal to a predetermined retail price for bulk-power generation services. In this analysis, that price is set equal to the expected (base-case) value of market price plus allowed MTC.

5. Retail-price reduction: The amount of money the utility receives is determined by the requirement that the sum of the market price of power plus the MTC is equal to some percentage, between 0 and 100, of the expected (base-case) value.

6. Cost sharing: The utility receives a fixed percentage, between 0 and 100, of the allowed TC recovery for the exogenous situation that actually occurs (Mechanism 3) plus all of the cost-reduction it achieves. Mechanism 3 is a special case of this one with the exogenous percentage equal to 100%.

7. Performance-based rate: The utility receives 100% of the allowed TC, based on the exogenous situation that actually occurs (Mechanism 3) minus an adjustment based on a predetermined reduction in utility generation costs.

Although this list includes seven mechanisms, several are modifications of others. Mechanism 4 is a special case of Mechanism 5. Mechanisms 6 and 7 are modifications of Mechanism 3. Mechanism 6 credits retail customers with a fixed percentage of the transition costs associated with exogenous factors rather than the 100% of Mechanism 3. Mechanism 7 credits retail customers with a fixed dollar amount, which the utility is expected to offset through its generation-cost-reduction efforts. These two mechanisms, which encourage the utility to cut its production costs, are consistent with the approach recommended by Joskow (1996).

Mechanisms 1, 2, and 3 set the amount of recovery the utility is to get; Mechanisms 4 and 5 set the prices that consumers face; and Mechanisms 6 and 7 seek to ensure benefits for the utility's customers. Where TC recovery is essentially guaranteed and therefor risk-free to utility shareholders, the PUC might elect to provide the utility a lower return on equity (e.g., at the rate for 30-year U.S. Treasury bonds). The PUC may want to adjust the percentage or dollar reductions associated with Mechanisms 6 and 7 to match the likely values of allowed TCs and potential utility cost reductions. For the cases discussed below, we assumed that the PUC would set the customer share of expected benefits at 25% of the utility's cost reductions. Thus, Mechanism 6 grants the utility 97% of its allowed TCs, and Mechanism 7 subtracts $10 million from the utility's allowed TCs.[*]

In Chapter 1, we discussed briefly some of the broad policy goals suggested for these mechanisms. Here, we convert these goals into specific objectives. In assessing the seven mechanisms listed above, PUCs might consider the four broad goals and supporting objectives shown in Table 4.

Table 4 also shows ORCED's implementation of each of these objectives. For example, if market prices increase, the objective to have the utility face incentives similar to those faced by nonregulated suppliers implies that the utility's losses should decline (i.e., its earnings should increase). Thus, the correlation between changes in market prices and utility earnings should be positive. Similarly, if the utility cuts its forced-outage rates through improved maintenance practices, its generation revenues will increase, lowering TCs; here, too, the utility's earnings should increase, and the correlation between changes in allowable TCs and utility earnings should be positive.

In a similar fashion, the prices that customers face, the sum of the allowed MTC plus spot prices, should move in the same direction as the market price.

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[*]Twenty-five percent of the average utility cost reduction of $41 million is equivalent to 3.3% of the average allowable TC of $307 million (0.25 × $41 million/$307 million = 0.033).

Table 4. Four cost-recovery goals and ORCED treatment thereof

Objective	ORCED quantification
1. The utility's operation of, and investment in, its generating resources should be consistent with the actions taken by the owners of similar resources in fully competitive bulk-power markets. Thus, the TC-recovery and trueup mechanism should not affect generation-related operation and investment decisions. This general principle leads to three subsidiary objectives designed to ensure that the utility is treated the same way that other suppliers are treated in competitive generation markets:	
■ The utility should be fully responsible for all future avoidable costs. That is, the recovery mechanism should not indemnify the utility for its future generation-related fuel costs, O&M costs, or capital costs; decommissioning costs might be an exception to this rule.	■ ORCED calculates the utility's total TC and its "allowed" TC. The latter term excludes fixed O&M costs, which are assumed to be avoidable.
■ The utility's earnings should respond to exogenous factors in the same way that the earnings do for other suppliers.	■ ORCED calculates the ratio of change in utility earnings to change in market price
■ The utility should face economic incentives to improve its generation productivity and cut costs. Thus, at least some of the money saved by a utility's productivity improvements should be retained by the utility.	■ ORCED calculates the percentage of utility cost reductions that the utility is allowed to keep
2. Retail customers should benefit from competition and should face market forces. This general principle leads to two subsidiary objectives, which may conflict with each other:	
■ Retail customers should face market-induced price changes.	■ ORCED calculates the ratio of change in retail generation price to change in market price
■ Future (market-based) retail prices for all customer classes should not exceed today's embedded-cost prices during the TC-recovery period.	■ ORCED calculates the change in retail generation price relative to base-case price
3. Neither customers nor shareholders should bear undue risks of over- or underrecovery	ORCED calculates the utility over- or underrecovery of TCs relative to that for Mechanism 3
4. The mechanism chosen should be simple to understand and to administer. It should not result in the equivalent of heavily litigated, annual rate cases.	See Chapter 5

In assessing the cases in which the utility undertakes cost-cutting actions, one must ask what motivates such actions. In the long run, the utility would want to improve its productivity to improve its earnings in competitive generation markets. In the short run, however, the utility, depending on the particular TC-recovery mechanism in place, may have little or no incentive to cut costs. For example, if the utility cuts its costs $27 million by improving heat rates (Scenario 11 in Table 2), it will keep only $1 million of that amount if Mechanism 2 is applied and it receives 100% of its allowed TC.[*] On the other hand, if the utility is permitted to keep 100% of the savings it generates (Mechanism 3), its losses decline by $26 million.

ANALYTICAL RESULTS

Table 5 and Fig. 2 show the results obtained for the base case, the situation that would occur if the expected conditions materialized. Each column of the table shows results for one of the seven mechanisms outlined above. For this situation, the first through fourth mechanisms yield identical results. The last three mechanisms reduce utility earnings and lower customer prices.

The rows in Table 5 show the effects of each recovery mechanism on utility earnings, retail prices, and risks. The first row shows the amount of money (in millions of dollars) the utility is authorized to recover from customers through the MTC for the particular mechanism. The second row shows the utility's loss with this amount of TC recovery.[#] The third row shows the percentage change in earnings from the base case relative to the percentage change in market price; a "good" mechanism will have a positive number here. The fourth row shows the percentage of its cost reductions the utility is allowed to keep; a percentage close to 100% is desirable here. The fifth row shows the MTC (in ¢/kWh). For some mechanisms, the MTC is based on (derived from) the amount of TC recovery allowed (row 1) and in other cases it is based on the allowed retail price (Mechanisms 4 and 5). Row 6 is the retail price that customers face, the sum of MTC plus the market price (in ¢/kWh). Rows 7 and 8 show percentage changes in the retail price of electricity relative to the change in market price and relative to the base-case retail price. Finally, row 9 shows the percentage over- or under-recovery that the utility experiences relative to what it would have received with 100% recovery for exogenous factors only (Mechanism 3).

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[*]This $1-million earnings increase arises from the utility's reduction in avoidable fixed costs, which otherwise are disallowed by the PUC. That is, $1 million of the total $27-million savings arises from the increased operation of these units, which reduces the per-kilowatt-hour fixed O&M costs.

[#]The present analyses assume that the utility earns its traditional return on equity (11%). Regulators could mitigate TCs by allowing utilities to earn a return *of* their TC investments but not necessarily *on* their TC investments. The California PUC allows the utilities to earn a return on their generation-related TCs equivalent to the long-term-bond interest rate, based on the belief that TC recovery is relatively risk-free.

Table 5. Performance of seven mechanisms for the base-case situation[a]

	Fixed recovery (expected value)	100% recovery for exogenous and endogenous factors	100% recovery for exogenous factors only	Fixed retail price (expected value)	5% price cut	Utility gets 100% of its cost reductions	
						+97% of recovery for exogenous factors	−$10 million cost adjustment
TC recovery allowed, M$	329	329	329	329	264	319	319
Utility earnings loss, M$	12.5	12.5	12.5	12.5	77.6	22.4	22.5
(ΔEarnings/base-case earnings)/ (ΔMarket price/base-case market price)	Market price equals base-case market price						
% of cost cuts utility keeps	Utility takes no generation cost-cutting actions						
Allowed MTC, ¢/kWh	1.00	1.00	1.00	1.00	0.80	0.97	0.97
Market price + allowed MTC, ¢/kWh	3.93	3.93	3.93	3.93	3.74	3.90	3.90
Δtotal price/Δmarket price	Market price equals base-case market price						
% diff from base = 3.93 ¢/kWh	0.0	0.0	0.0	0.0	−5.0	−0.8	−0.8
% over- or underrecovery relative to Mechanism 3	0	0	0	0	20	3	3

[a]The utility's allowed TC is $329 million. The market price of power is 2.94¢/kWh.

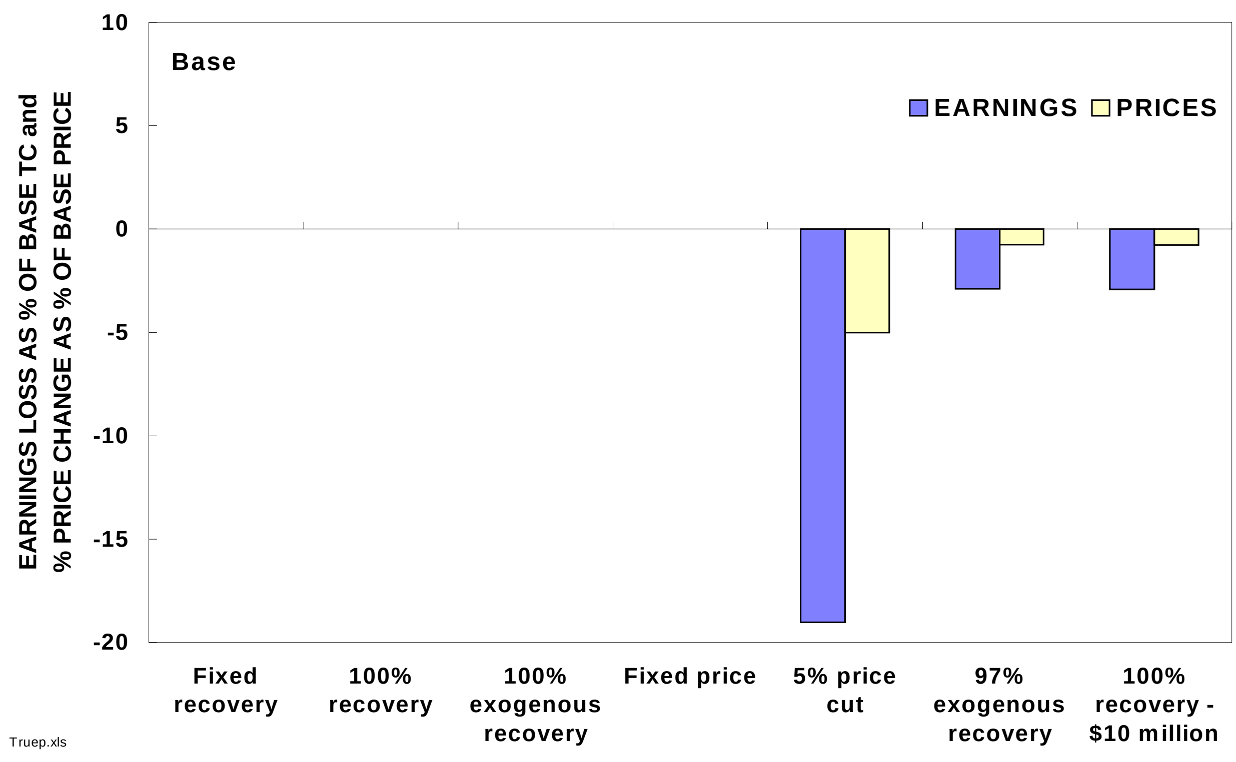

Fig. 2. Base-case results showing utility earnings loss as a percentage of base-case TC of $324 million and change in retail price as a percentage of base-case price of 3.93¢/kWh.

Table 6 and Fig. 3 show the results if the regional load is 5% higher than expected (the utility's load is unchanged in this case). Higher loads lead to a higher market price, increasing from 2.94¢/kWh in the base case to 3.00¢/kWh in this case. The higher price improves the utility's financial picture. Its revenues increase by $24 million more than its costs increase. Because its generators are used more intensively in this case, the utility's fixed O&M costs per kilowatt hour go down; thus, its disallowed TCs decline from $13 to $11 million.

Table 6. Performance of seven mechanisms for the situation in which the regional load is 5% higher than expected[a]

	Fixed recovery (expected value)	100% recovery for exogenous and endogenous factors	100% recovery for exogenous factors only	Fixed retail price (expected value)	5% price cut	Utility gets 100% of its cost reductions: +97% of recovery for exogenous factors	Utility gets 100% of its cost reductions: −$10 million cost adjustment
TC recovery allowed, M$	329	307	307	310	245	298	297
Utility earnings loss, M$	−11.5	10.8	10.8	8.1	73.1	20.0	20.8
(ΔEarnings/base-case earnings)/ (ΔMarket price/base-case market price)	3.5	0.3	0.3	0.6	−8.8	−1.1	−1.2
% of cost cuts utility keeps	Utility takes no generation cost-cutting actions						
Allowed MTC, ¢/kWh	1.00	0.93	0.93	0.94	0.74	0.90	0.90
Market price + allowed MTC, ¢/kWh	3.99	3.93	3.93	3.93	3.74	3.90	3.90
Δtotal price/Δmarket price	1.00	−0.14	−0.14	0.00	−3.32	−0.61	−0.65
% diff from base = 3.93 ¢/kWh	1.5	−0.2	−0.2	0.0	−5.0	−0.9	−1.0
% over- or underrecovery relative to Mechanism 3	0	0	1	20	3	3	3

[a]The utility's allowed TC is $307 million. The market price of power is 3.00¢/kWh.

Because the utility undertook no direct cost-cutting actions, Mechanisms 2 and 3 yield identical outcomes. Comparing Tables 5 and 6 shows that the utility loses less money under each mechanism than it does in the base case. Thus, the utility, like its competitors, does better when market prices are higher. However, the mechanisms differ substantially in the amount of losses the utility experiences: from a high of $73 million with a mandated 5% price cut to a $12 million gain with fixed recovery.

The MTC is equal to or lower than its corresponding base-case values for each of the mechanisms. Although the market price is higher, customer prices are higher for only the first mechanism. Customer prices are unchanged for Mechanisms 4 and 5 because these mechanisms specify what the retail price is to be.

The utility overrecovers with Mechanism 1 (fixed recovery) and substantially underrecovers with Mechanism 5 (5% price cut).

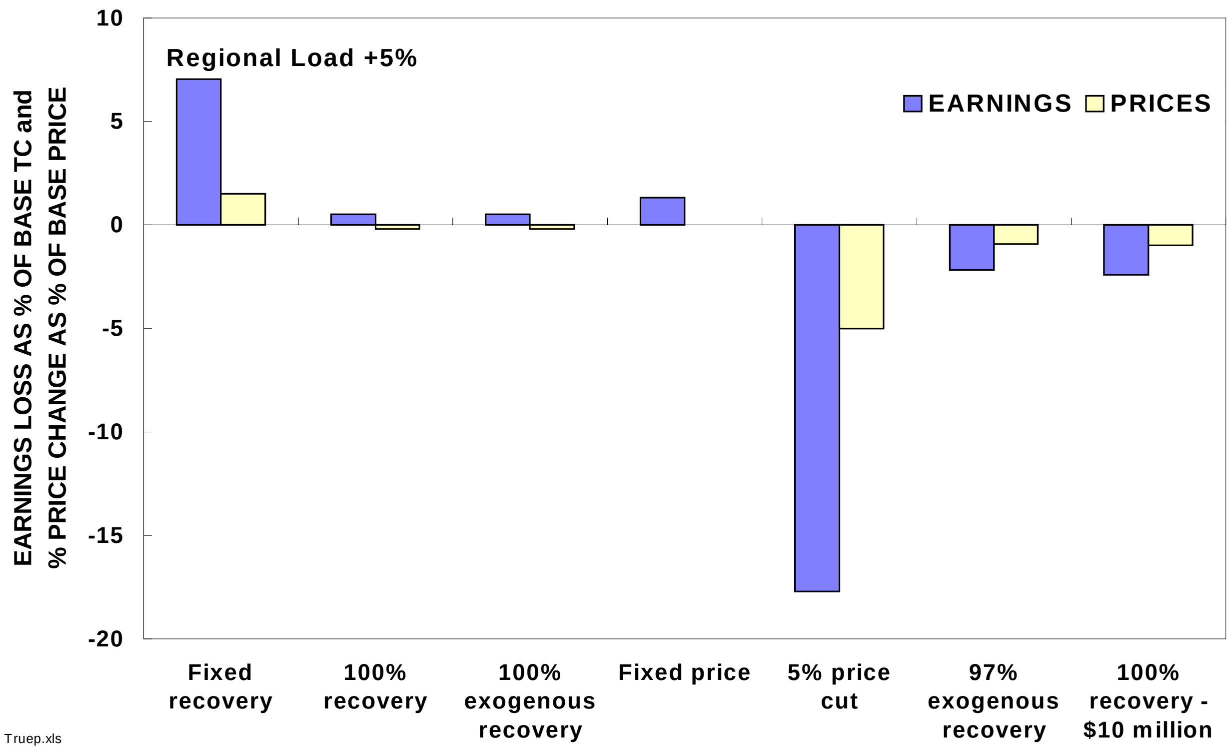

Fig. 3. **Utility earnings loss as a percentage of base-case TC and change in retail price as a percentage of base-case price when regional load is 5% higher than expected.**

Table 7 and Fig. 4 show results for a case in which the utility takes action to improve the productivity of its generating resources, cutting its fixed O&M costs by 10%. This action has no effect on the market price of power nor on the amount of power that the utility sells.* It does, however, have large effects on allowed TCs. In particular, the amount of disallowed TC drops from $13 million to $6 million. As with the prior case, the utility loses less money under each mechanism than it did in the base case. The difference is limited for Mechanism 2, which transfers all of the utility's "allowed" cost savings to retail customers.

Customer prices are the same as the comparable base-case values except for Mechanism 2. For Mechanism 2, the price is lower than its base-case counterpart because this mechanism assigns all the benefits of the utility's cost reductions to customers. These comparisons suggest that striking an appropriate balance between giving a meaningful incentive to the utility to cut costs and ensuring that retail customers benefit will not be simple.

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*We assume that the market price of power is based on generator bids that reflect their variable costs (fuel plus variable O&M) only. Thus, fixed O&M costs have no effect on market prices and therefore have no effect on the amount of power the utility buys or sells at wholesale.

Table 7. Performance of seven mechanisms for the situation in which the utility cuts its fixed O&M costs by 10%[a]

	Fixed recovery (expected value)	100% recovery for exogenous and endogenous factors	100% recovery for exogenous factors only	Fixed retail price (expected value)	5% price cut	Utility gets 100% of its cost reductions: +97% of recovery for exogenous factors	Utility gets 100% of its cost reductions: −$10 million cost adjustment
TC recovery allowed, M$	329	319	329	329	264	319	319
Utility earnings loss, M$	−3.8	6.3	−3.8	−3.8	61.2	6.1	6.2
(ΔEarnings/base-case earnings)/ (ΔMarket price/base-case market price)	Market price equals base-case market price						
% of cost cuts utility keeps	100	0	100	100	100	100	100
Allowed MTC, ¢/kWh	1.00	0.97	1.00	1.00	0.80	0.97	0.97
Market price + allowed MTC, ¢/kWh	3.93	3.90	3.93	3.93	3.74	3.90	3.90
Δtotal price/Δmarket price	Market price equals base-case market price						
% diff from base = 3.93 ¢/kWh	0.0	−0.8	0.0	0.0	−5.0	−0.8	−0.8
% over- or underrecovery relative to Mechanism 3	0	3	0	0	20	3	3

[a]The utility's allowed TC is $319 million. The market price of power is 2.94¢/kWh. The utility cuts costs by $16 million, of which $10 million are allowed TCs.

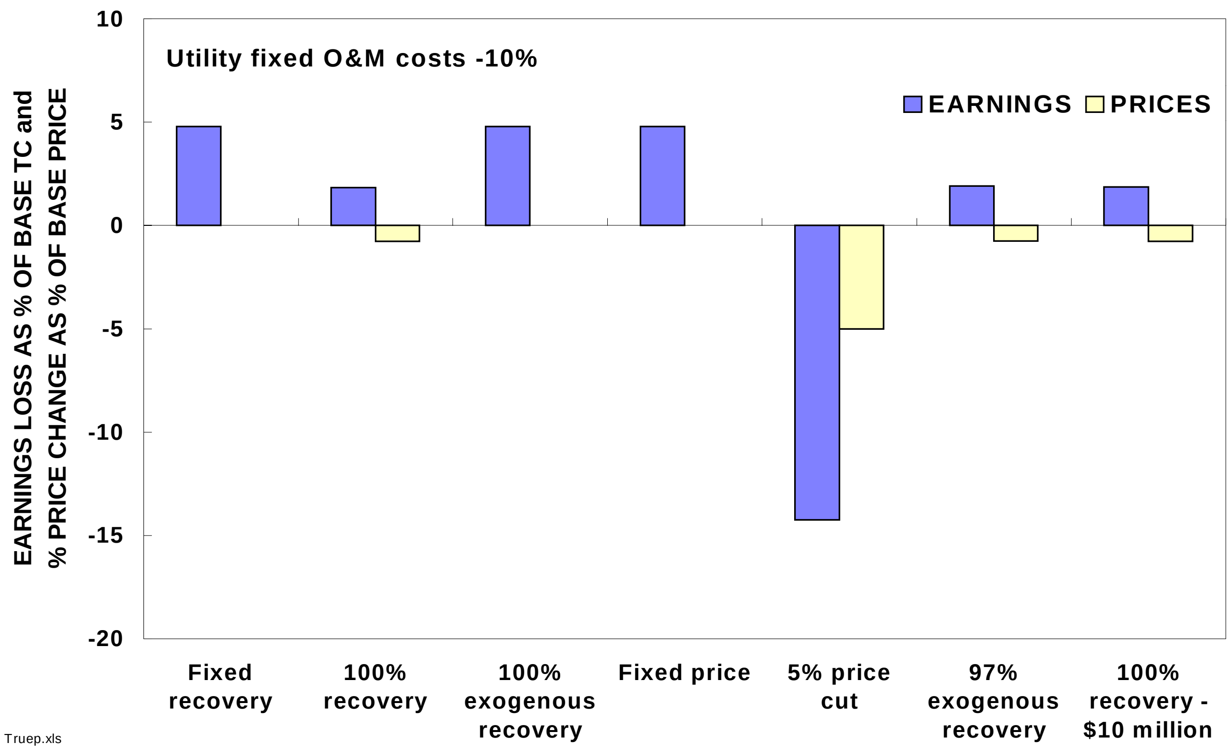

Fig. 4. Utility earnings loss as a percentage of base-case TC and change in retail price as a percentage of base-case price when the utility cuts its fixed O&M costs by 10%.

Requiring a guaranteed reduction in retail prices (the sum of market price plus MTC) has a much greater proportional impact on utility earnings than it has on customer prices (Fig.1). For the situation modeled here, every one-percentage-point reduction in retail price increases utility losses by about 3.6% of its annualized capital cost. For example, the base case involves a $13 million loss to the utility because of disallowed fixed O&M costs at some of its units. The retail price for this base case is 3.93¢/kWh. A 5% reduction in price to 3.73¢/kWh requires a $66 million increase in utility losses, equivalent to 18% of its capital cost. The percentage loss is 3.6 times the 5% reduction in retail price.

These results are not surprising. Utility earnings are the residual, what remains from revenue after all costs (including fuel, labor, taxes, and interest on bonds) are paid. A percentage reduction in total revenue unavoidably has a much larger percentage effect on earnings. Thus, absent substantial utility cost-cutting actions, it may not be possible to materially reduce retail electricity prices without greatly damaging the utility's financial situation.

INTERPRETATION OF RESULTS

The preceding discussion showed the details of three scenarios: the base case (expected situation), higher regional loads (an example of a change in an exogenous factor), and lower fixed O&M costs at the utility's generating units (a change in an endogenous factor). The results (Tables 5, 6, and 7) suggest that mechanisms that do well in meeting one public-policy objective may not do well in meeting other objectives.

Here we summarize results across all 33 scenarios on the performance of each of the seven mechanisms relative to five of our six policy objectives. (Chapter 5 discusses the sixth objective: administrative simplicity.) We begin by examining cases in which only exogenous factors vary, then examine cases in which only endogenous factors vary, and finally discuss cases in which both exogenous and endogenous factors vary (Table 8).

We examine five specific objectives shown on the right side of Table 4:

- Retail prices do not exceed the base-case (expected) value
- Retail prices are positively correlated with market prices (i.e., retail prices go up and down with bulk-power market prices)*
- Utility earnings respond to market forces in the same way that earnings for other, competitive generators do (i.e., earnings go up and down with market prices)
- Utility earnings respond to utility cost-cutting actions (i.e., earnings vary directly with cost reductions)
- The utility neither over- nor underrecovers its costs relative to what it would receive with Mechanism 3 (100% recovery for exogenous factors)

The top part of Table 8 shows results for the eight cases in which only exogenous factors vary. The first row shows the percentage change in retail electricity prices relative to the base case for each mechanism; negative values represent benefits to customers. Prices decline slightly for Mechanisms 1 through 3, are by definition unchanged for Mechanism 4, decline by

*The first two objectives can conflict with each other. For example, if market prices rise, the second objective calls for retail prices to rise also. However, the first objective calls for a cap on prices.

the prespecified 5% for Mechanism 5, and decline for Mechanisms 6 and 7. The second row shows the ratio of change in retail price to change in market price; positive values mean that the prices customers face move with market prices. This occurs consistently only for Mechanism 1. For all the other mechanisms, retail prices are either insensitive to changes in market prices or move slightly in the opposite direction. Row 3 shows that utility earnings consistently move in the same direction as earnings for other generators for Mechanisms 1 through 4. The fourth objective, which relates to utility earnings in the face of utility cost reductions, is not relevant here. Only two mechanisms (fixed recovery and 5% price cut) expose shareholders and customers to substantial risks of over- or underrecovery (or payment) for transition costs.

The second part of Table 8 shows how the different mechanisms perform for the four cases in which the utility undertook cost-cutting activities. Retail prices met the first objective of not increasing for all seven mechanisms. Because market prices hardly changed at all in these five cases, the second and third objectives are not relevant here. The fourth row shows the percentage of allowed cost reductions that the utility is able to keep under each mechanism. Other than Mechanism 2, the mechanisms all perform well on this objective, allowing the utility to keep all of the savings associated with its cost-reduction efforts. Only two mechanisms (100% recovery for all factors and 5% price cut) expose shareholders and customers to substantial risks.

The third part of Table 8 summarizes results for the 20 cases in which both exogenous and endogenous factors vary. Retail prices increase slightly for Mechanisms 1 and 3, and remain constant or decline for the other mechanisms. Retail prices consistently move in the same direction as market prices only for Mechanism 1. Utility earnings consistently move as would competitor earnings for Mechanisms 1 and 2. The percentage of cost reductions that the utility is allowed to keep is essentially the same as above. Three mechanisms (fixed recovery, 100% recovery for all factors, and 5% price cut) expose shareholders and customers to substantial risks.

The bottom part of Table 8 shows the correlation coefficients for two of the objectives: (1) utility earnings vary with market prices and (2) retail prices vary with market prices. Mechanism 1 is the best (has the highest negative correlation) with respect to ensuring that the utility’s earnings respond to market forces, and Mechanisms 4 and 5 are the worst (Fig. 5). Mechanism 1 is the best (has the highest positive correlation) with respect to ensuring that retail prices move with changes in market prices, and Mechanism 2 is the worst (Fig. 6).

Table 8. Performance of mechanisms in meeting key public-policy objectives[a,b]

Objective/mechanism	Fixed recovery (expected value)	100% recovery for exogenous and endogenous factors	100% recovery for exogenous factors only	Fixed retail price (expected value)	5% price cut	Utility gets 100% of its cost reductions: +97% of recovery for exogenous factors	Utility gets 100% of its cost reductions: −$10 million cut
Cases in which only exogenous factors vary							
Retail prices							
- Do not increase vs base case (% price change from base case)	−0.4	−0.1	−0.1	0.0	−5.0	−0.8	−0.8
- Move with market prices (ratio of change in retail price to change in market price)	1.0	−0.1	−0.1	0.0	0.0	0.0	−0.1
Utility earnings							
- Respond to market forces as do competitor earnings	Y	Y	Y	Y	-	-	-
- Respond to utility cost cuts	Not applicable						
% over- or underrecovery	7	0	0	0	19	3	3
Cases in which only endogenous factors vary							
Retail prices							
- Do not increase vs base case (% price change from base case)	0.0	−2.0	0.0	0.0	−5.0	−0.7	−0.7
- Move with market prices	Not applicable						
Utility earnings							
- Respond to market forces as do competitor earnings	Not applicable						
- Respond to utility cost cuts (% of cuts that utility keeps)	100	0	100	100	100	100	100
% over- or underrecovery	0	8	0	1	20	3	3
Cases in which exogenous and endogenous factors vary							
Retail prices							
- Do not increase vs base case (% price change from base case)	0.2	−2.5	0.4	0.0	−5.0	−0.4	−04
- Move with market prices (ratio of change in retail price to change in market price)	1.0	−0.1	0.1	0.0	0.0	0.1	0.1
Utility earnings							
- Respond to market forces as do competitor earnings	Y	Y	-	-	-	-	-
- Respond to utility cost cuts (% of cuts that utility keeps)	100	0	100	92	92	100	100
% over- or underrecovery	10	11	0	3	21	3	3
Correlation coefficients							
Earnings loss − base-case loss and change in market price	−0.90	−0.50	−0.41	−0.36	−0.36	−0.44	−0.41
Retail price − base-case price and change in market price	1.00	−0.28	0.35	0.00	0.00	0.43	0.35

[a]The numerical results differ slightly among the top three parts because the mix of exogenous, endogenous, and exogenous-plus-endogenous scenarios differs across the parts.

[b]A "Y" means that the mechanism consistently performs well on this objective, a "y" means that the mechanism generally performs well, and a "-" means that the mechanism's performance is neutral or mixed.

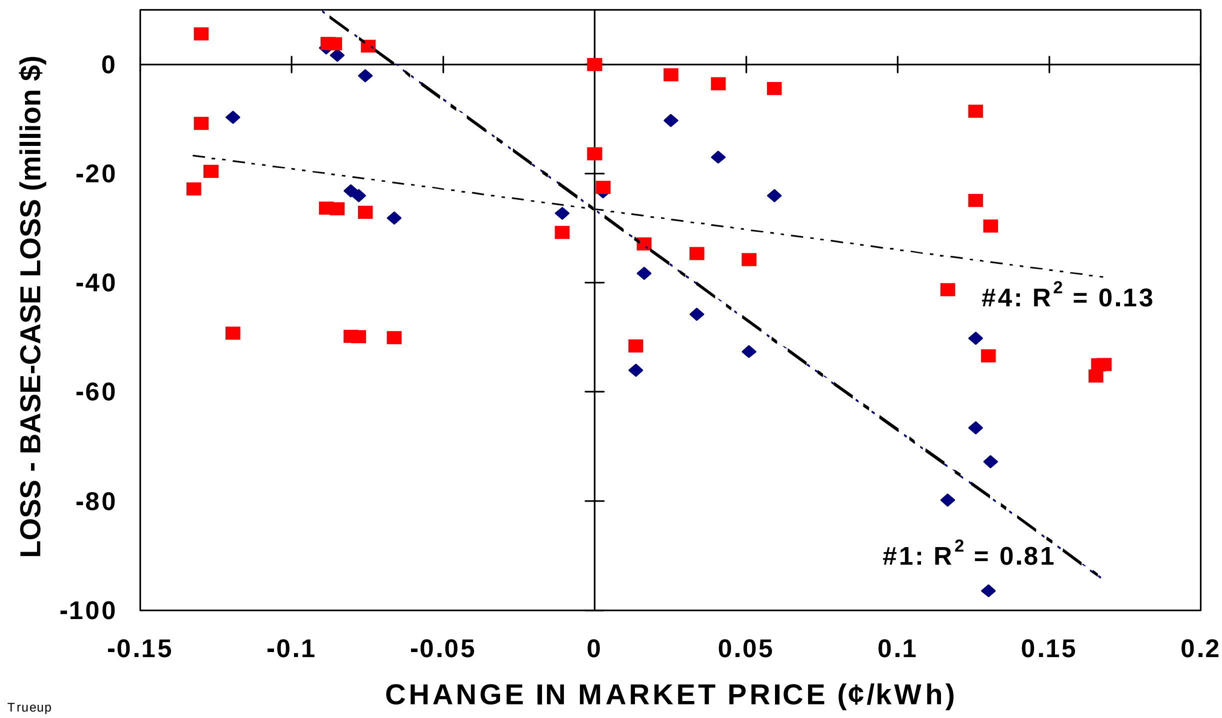

Fig. 5. **Correlation between change in utility earnings loss and change in bulk-power market prices for 33 cases for Mechanisms 1 and 4.**

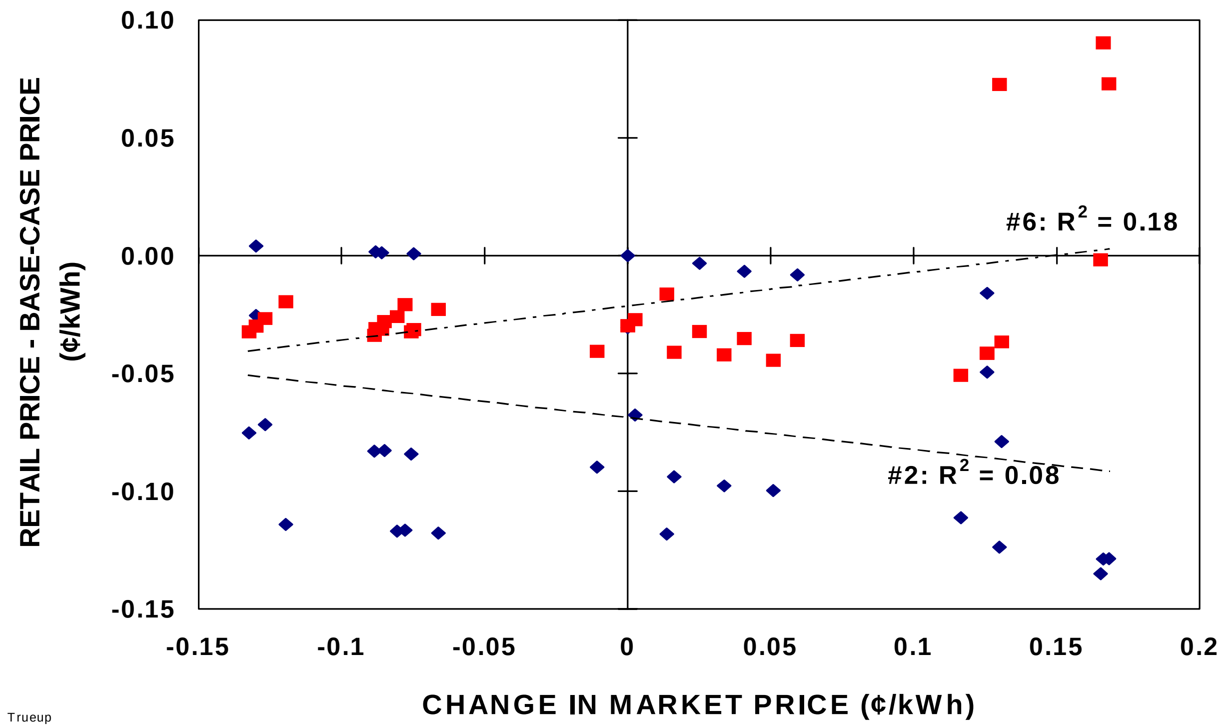

Fig. 6. **Correlation between change in retail generation price and change in bulk-power market prices for 33 cases for Mechanisms 2 and 6.**

IMPLEMENTATION DETAILS

One of the key criteria for assessing alternative cost-recovery and trueup mechanisms is the ease with which they can be implemented and administered by the PUC. The first mechanism, prior determination of a fixed amount of TCs to be recovered by the utility, is simple to administer. The PUC must decide up front on the dollar amount that the utility will be allowed to collect each year and the collection method (e.g., as an adder to each customer's energy charge in ¢/kWh or as an adder to the monthly customer charge in $/month). Because projections of the number of customers and their electricity use will be incorrect, a balancing account must be established for under- or overcollections. The trueup required here is simple because it adjusts a fixed amount by a well-defined denominator (e.g., total retail electricity sales or total number of retail customers).

Mechanisms 4 and 5, which fix the retail price of electricity, require an unambiguous measure of the bulk-power market price. In states where a power exchange exists, such as those within the Pennsylvania-New Jersey-Maryland (PJM) Interconnection, this requirement may be simple to meet. PJM publishes hourly spot prices, which are available for all 8760 hours of the year. (Other sources, such as *Electric Power Analyst*, publish peak and offpeak, firm and nonfirm prices for several locations throughout the United States and Canada.) In other regions, the PUC may have to "create" an index to measure competitive prices. For example, in Oregon, the PUC might choose to create an index that is a weighted average of the indexes at the California-Oregon border, the Mid-Columbia dams, and perhaps other locations in the Pacific Northwest. This requirement for an empirically determined competitive market price with a predetermined method is key to meeting the objective of administrative simplicity.

Under these fixed-price mechanisms, the utility is permitted to collect an MTC from customers equal to the difference between the PUC-specified retail price of energy and the market price of energy. (Both sets of prices will differ across customer classes because of interclass differences in load shapes and in transmission and distribution losses.) That is, the amount of TCs that the utility collects is derived from the difference between the fixed retail price and the actual market price. Given the existence of an agreed-upon market price, these mechanisms are simple to administer.

The remaining mechanisms (2, 3, 6, and 7) require annual calculations of allowed TC, which could turn out to be complicated. These mechanisms require calculation of TC amounts related to changes in exogenous factors, endogenous factors, or both. As noted above, one of the key objectives of a TC-recovery and trueup mechanism is that it be simple to administer.

A mechanism that involved the equivalent of a full-blown rate case every year could be considered anticompetitive on both practical and policy grounds.

A straightforward way to calculate allowed TCs associated with exogenous factors each year could proceed as follows. First, the PUC in its *a priori* determination of the expected TC amount and the allowed recovery mechanism would approve the assumed characteristics of the utility's generating resources. These characteristics would include the heat rates, fuel costs, maintenance- and forced-outage rates, variable O&M costs, and fixed O&M costs for each generating unit and power-purchase contract. In addition, the PUC would determine the amount of administrative and general expenses that can be assigned to generation and the amount of general plant that can be similarly assigned. Presumably, these assumptions would be the same as those used in the PUC's final determination of the expected TC amount for that utility. Joskow (1996) emphasizes, as we do here, the importance of this "up-front approach [that] requires that avoidable costs and generator performance for many years into the future be estimated up front ... ."

Second, the PUC would specify the use of a particular production-costing algorithm to be used in calculating the utility's generation-related revenues and operating costs. This algorithm could be one of those used in the litigation of TC amounts. It could also be another computer model. For example, the PUC might choose to use a simple production-costing method, such as one that uses load-duration curves instead of the hour-by-hour detail of chronological methods. The results obtained with this simpler approach could be calibrated to either the results obtained with a more detailed model or against historical data. The calibration method would then be applied to calculations for future years.

Third, the PUC would specify the use of a method to calculate competitive bulk-power prices in the future, as discussed above.

To determine the utility's allowed TCs in a particular year, the utility would run the predetermined production-costing model with the predetermined assumptions concerning the utility's generating resources (steps 1 and 2 above) against the hourly market prices from step 3. This straightforward calculation produces values of the utility's generation-related revenues and operating costs. The beauty of this approach is that it uses actual market prices and therefore reflects changes in competitive bulk-power markets over time. Because the method uses predetermined assumptions about the utility's generating resources, any improvements that the utility makes in the way it actually operates its generating resources have no effect on the allowed TC value.

The results obtained with the approach outlined here should engender few conflicts. The input data on the utility's generating resources have been determined beforehand, the sources of information on the bulk-power price of electricity have been determined beforehand, and the method used to calculate production costs and revenues has been determined beforehand. All that remains is to wait until data on spot prices are available for the year in question and then to apply these data and assumptions to the calculation method. Because the data, assumptions, and modeling approach are all predetermined, there should be little left to litigate, a welcome and unusual situation.

A committee of the Ohio General Assembly (1998) recently proposed a similar approach to deal with TCs other than those associated with regulatory assets. The utility's allowable production revenues would be based on a fraction of the difference between the utility's actual cost of production in the year 2000 and a benchmark reflecting regional production costs in 1995 (assumed to "approximate the long-run, average cost of electricity production"); the allowed fraction declines each year during the transition period (110% of this difference in year 1, then 90%, 60%, 40%, 20%, and zero thereafter).

Mechanisms that provide an explicit incentive to the utility to cut its generation costs (endogenous factors) require additional calculations that can complicate determination of the appropriate sharing of savings between the utility's shareholders and retail customers. Mechanism 2, which grants the utility 100% of actual TCs in response to changes in both exogenous and endogenous factors, requires a separate calculation of the effects of the utility's cost reductions on allowed TCs. This mechanism automatically assigns all of the benefits of the utility's cost reductions to customers.

This mechanism requires measurement of and agreement on these cost reductions. The utility has a strong incentive to underreport its cost savings. To the extent it does so, it does not have to share them with customers. This incentive argues for giving the utility 100% of its cost reductions, which is why all but Mechanism 2 avoid this complicated and potentially litigious step.

Although Mechanism 3 is administratively simple, it may be considered inequitable because customers gain no benefits from utility cost-cutting efforts. A compromise may be to grant the utility less than 100% of the transition costs associated with *exogenous* factors plus 100% of the transition costs associated with *endogenous* factors (Mechanism 6) or to grant the utility 100% of the transition costs associated with *exogenous* factors and to reduce this amount by a predetermined performance-based requirement (e.g., a requirement that the utility achieve a certain level of generation-cost reductions that are passed on to retail customers, Mechanism 7).

CONCLUSIONS

The specifics of cost-recovery and trueup mechanisms have not received sufficient attention to date. The design of such mechanisms to meet important public-policy objectives, the subject of this report, may well be *the* remaining critical issue in transition costs.

We reviewed the limited literature on the subject, which uncovered a few sets of broad policy guidelines for the mechanisms that utilities could use to recover transition costs from their retail customers. We were unable to locate any quantitative studies that showed how well-defined mechanisms would perform in meeting well-defined objectives.

These mechanisms should meet a diversity of equity and efficiency goals. In particular, these mechanisms should balance risks between utility shareholders and retail customers, and they should motivate the utility to manage its generating resources in a cost-cutting, innovative, and competitive fashion.

We defined seven mechanisms that PUCs, utilities, and other stakeholders might consider as they develop TC-recovery strategies. We used a simple but realistic representation of competitive bulk-power markets to estimate bulk-power electricity prices and a particular utility's revenues and costs under a variety of conditions. These conditions include changes in both exogenous (external to the utility and beyond its control) and endogenous (within the utility's control) factors. We then calculated retail electricity price (equal to the sum of the bulk-power market price plus the market transition charge), TC recovery, and utility earnings for seven mechanisms for 33 cases. Table 9 summarizes the overall findings on the performance of these mechanisms with respect to administrative simplicity, benefits to retail customers, incentives to the utility, and risks.

Mechanism 1 performs well against the first five objectives; its weakness, however, is its inability to adjust actual cost-recovery amounts for subsequent changes in any factors that affect the accuracy of the *a priori* TC estimate. All the mechanisms, except for Mechanism 2 should be simple to administer. (It is no accident that so many of these mechanisms can be implemented without undue controversy because we eliminated many mechanisms that failed this all-important test.)

Mechanisms 4 and 5, which predetermine retail electricity prices, guarantee that prices will not increase, which is a strong advantage for these two mechanisms. On the other hand, these mechanisms—because they guarantee fixed prices—ensure that customers do not experience any market-induced changes in bulk-power prices. For these two mechanisms, politics and economics conflict. Also, Mechanism 5 exposes customers and the utility to substantial risks of over- or underrecovery of TCs.

Table 9. Comparison of alternative cost-recovery and trueup mechanisms[a]

Objective/mechanism	Fixed recovery (expected value)	100% recovery for exogenous and endogenous factors	100% recovery for exogenous factors only	Fixed retail price (expected value)	5% price cut	Utility gets 100% of its cost reductions	
						+97% of recovery for exogenous factors	–$10 million cost adjustment
Simple to administer	Y	N	Y	Y	Y	Y	Y
Retail prices							
- Do not increase from base case	Y	Y	y	y	Y	Y	Y
- Move with market prices	Y	n	y	N	N	y	y
Utility earnings							
- Respond to market forces	Y	Y	y	y	-	-	-
- Respond to utility cost reductions	Y	N	Y	Y	Y	Y	Y
Little risk of over- or under-recovery	n	n	Y	Y	N	y	y

[a]A "Y" means that the mechanism consistently performs well on this objective, a "y" means that the mechanism generally performs well, a "-" means that the mechanism's performance is neutral or mixed, an "n" means that the mechanism generally performs poorly, and an "N" means that the mechanism consistently performs poorly.

The last two mechanisms are intended to ensure that retail customers gain some benefits from any utility cost-cutting efforts. Because of the potential administrative difficulties in measuring the effects of such utility efforts, these mechanisms use indirect methods to achieve this goal. Mechanism 6 provides the utility with full credit for any cost reductions it achieves, but allows it to recover less than 100% of the otherwise allowed TCs associated with exogenous factors. Mechanism 7 allows the utility to recover 100% of allowed TCs and then subtracts a dollar amount that the PUC determines the utility should be able to achieve in the operation of its generation resources. This predetermined amount is the "share" of utility cost reductions that retail customers get.

Ultimately, PUCs will select a cost-recovery and trueup mechanism based on its weighting of various public-policy objectives (including those discussed here). As a starting point, we recommend that PUCs focus their attention on the last two mechanisms. We believe that the certainty of the fixed-cost-recovery mechanism (Mechanism 1) is too risky for consumers and utility shareholders. Even modest changes in some of the assumptions that would underlie the determination of this fixed amount could dramatically change the amount allowed for recovery. Thus, either customers would pay too much to the utility, or utility shareholders would be undercompensated relative to what the PUC intended.

The second mechanism, dollar for dollar recovery of all costs, could prove difficult to administer because it requires the PUC to measure (i.e., audit) the effects of the utility's generation-cost-cutting efforts. This method also eliminates any incentive that the utility might otherwise have to improve its productivity and cut costs.

Mechanism 3, 100% recovery for exogenous factors only, is workable and may merit PUC consideration. We prefer Mechanisms 6 and 7 because they ensure that retail customers gain some benefits over time.

Mechanisms 4 and 5, which fix retail electricity price, offer clear benefits to customers. We do not favor these mechanisms because these consumer benefits come with a high price tag. A mandated price reduction that is nontrivial (e.g., a 5% reduction in retail price, which is roughly equivalent to a 10% reduction in generation price) could seriously injure utility shareholders by requiring them to accept substantial earnings losses. Also, these mechanisms insulate retail customers from changes in market prices, one of the key features (and benefits) of competitive markets.

The last two mechanisms are similar in that they both begin with calculation of transition costs based on 100% adjustment for changes in exogenous factors (Mechanism 3). Mechanism 6 subtracts a fixed percentage (3% in the present analysis) of the TC amount, as calculated above, from what shareholders would otherwise collect and transfers these funds to retail customers. Mechanism 7 subtracts a predetermined dollar amount ($10 million a year in the present analysis) from what shareholders would otherwise collect and transfers these funds to retail customers.

As PUCs deliberate on an appropriate mechanism to use, they may want to refine the objectives that such a mechanism should meet. Specifically, changing the percentage reduction in retail price (Mechanism 5), the percentage of cost recovery for exogenous factors (Mechanism 6), or the prespecified cost reduction (Mechanism 7) could affect the performance of the mechanisms relative to the chosen objectives. A PUC may also want to consider additional mechanisms beyond those developed here. Finally, a PUC will want to obtain the results of utility-specific analyses for each jurisdictional utility for each mechanism of interest.

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