Public Utilities Commission

State of Minnesota

Utility Rates Study

June 2010

REPORT TO THE LEGISLATURE: UTILITY RATES STUDY AS REQUIRED BY LAWS OF MINNESOTA, 2009, CHAPTER 110

Submitted by the
Minnesota Public Utilities Commission

June 2010

INTRODUCTION

Laws of Minnesota 2009, Chapter 110 (S.F. No. 550) require the Minnesota Public Utilities Commission (MPUC) to prepare a Utility Rates Study. Specifically, the MPUC is to assess special mechanisms that allow cost recovery outside a general rate-case proceeding for specific kinds of expenditures. The specific issues the MPUC must address are as follows:

- an assessment of the impact of automatic cost-recovery mechanisms on prices charged to utility consumers compared to traditional cost-recovery mechanisms
- an assessment of the impact of automatic recovery mechanisms on the level of customer understanding of utility rates compared to traditional cost-recovery mechanisms
- an assessment of alternative forms of utility rate regulation that may be used in place of automatic cost-recovery mechanisms
- methods to improve administration and customer understanding of automatic cost-recovery mechanisms [1]

In an effort to develop resources for the report, the Commission sought the assistance of the National Regulatory Research Institute (NRRI). Besides providing topical materials, the NRRI published a report in September of 2009 entitled "How Should Regulators View Cost Trackers?" A copy of that report is incorporated as part of this report as Attachment A. The Commission also participated in an NRRI national webinar entitled "The Two Sides of Cost Trackers: Why Regulators Must Consider Both," which occurred on October 27, 2009. In addition, the NRRI created a "Knowledge Community" on cost trackers on its web page. Knowledge Communities are blogs open to regulatory commission personnel for purposes of sharing information and discussing topics of mutual interest.

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[1] The language from the Law is as follows:

> Sec. 33. **UTILITY RATES STUDY.** The Public Utilities Commission, in consultation with the Office of Energy Security, shall conduct a study of automatic cost-recovery mechanisms and alternative forms of utility rate regulation. This study shall include an assessment of the impact of automatic cost-recovery mechanisms on prices charged to utility consumers compared to traditional cost-recovery mechanisms, an assessment of the impact of automatic recovery mechanisms on the level of customer understanding of utility rates compared to traditional cost-recovery mechanisms, and an assessment of alternative forms of utility rate regulation that may be used in place of automatic cost-recovery mechanisms. The study shall also address methods to improve administration and customer understanding of automatic cost-recovery mechanisms. The commission shall submit this report to the legislature on or before June 30, 2010. The commission may assess public utilities for the cost of the study. The assessment is not subject to a cap on assessments provided by section 216B.62 or any other law.
> **EFFECTIVE DATE.** This section is effective the day following final enactment.

The Commission also convened a stakeholder open forum on January 29, 2010. Participants included: Xcel Energy, Minnesota Power, Otter Tail Power, Alliant Energy, Great River Energy, Dakota Electric Cooperative Association, CenterPoint Energy, the Minnesota Chamber of Commerce, the Izaak Walton League, the Office of the Attorney General, the Office of Energy Security (OES), Senate staff members, and representatives of large industrial customers. In addition, written comments were received from several parties on February 19, 2010 (under docket number E,G-999/CI-09-1338).

Background – Cost Recovery in Rate Cases

Setting rates for utilities is based on the principle of providing a reasonable opportunity[2] to earn a rate of return that recovers costs that were prudently incurred and necessary for the provision of safe and reliable utility services, including financing costs and a reasonable rate of return to investors. This opportunity is a condition of economic regulation as it has evolved in the United States over more than 100 years whereby entities deemed to be "affected with a public interest"[3] have been granted exclusive franchises (i.e., monopolies) for specific service areas and, in return, are subject to rate regulation by a public body, e.g., a state utility commission. The exclusive franchise obviously affords considerable financial security; the public rate regulation ensures that franchise authority is not abused.

State utility commissions traditionally make the determination of whether costs were prudently incurred, were necessary for the provision of reliable utility service, and were assigned a reasonable return as part a general rate case proceeding. A formal rate case includes a detailed review of all financial factors affecting utility operations. All revenue and cost categories are reviewed: those that increase as well as those that decrease. The goal is to establish rates that are reasonable (i.e., adequate to provide safe and reliable service) and also provide sufficient return to allow utilities to attract capital on reasonable terms to finance capital investments. So the process of setting rates that are in the public interest requires a balancing of utility financial viability with a sense of what is reasonable for ratepayers.

The rate level is established in a rate case using a "test year," which is a representative 12 month period of normal utility operations. In Minnesota, utilities may use a historical test year adjusted for known and measurable changes, or a forecasted test year. Under either type of test year, the objective is to reflect normal utility operations for the time period the new rates are likely to be in effect. For example, normal weather is assumed when estimating expected revenues and expenses for the test year.

Under traditional ratemaking principles, utilities may not change rates charged to customers outside of a rate case. Costs related to new plant investments, for example, are not reflected in

[2] "Opportunity" refers to a prudently-managed utility having a good chance of earning its authorized rate of return; it is not a guarantee or an entitlement that the authorized return will be earned each year.
[3] *Munn v. Illinois*, 94 U.S. 113 (1877)

rates until the plant is completed and providing service to customers, and related investments and expenses have been determined by the Commission to be prudent and reasonable through review in a rate case.

Rate cases involve many complex issues and take time to complete. As a result, the traditional rate-making process involves a delay between the incurrence of costs and the implementation of rates that recover these costs. In regulatory parlance, this is called "regulatory lag."[4] During the period between rate cases, rates remain at the level established in the last rate case decision; i.e., they "lag" the changing conditions since the rate case.

If a utility's costs are generally increasing during the period between rate cases, unchanging rates will make it more difficult for the utility to have a reasonable opportunity to earn its authorized return. Under these conditions, the opportunity to recover costs and to earn the authorized return will depend on the utility's ability to achieve greater efficiencies in operations; i.e., the unchanging rates create efficiency incentives. As that potential is exhausted, a new rate case filing becomes more likely. On the other hand, if costs generally decline and/or revenues increase after a rate case process, the established rates virtually assure recovery, and will enhance the utility's ability to earn its authorized return; it may result in over-recovery in some situations. So lag between rate cases can have varying effects on the opportunity the utility has to recover costs and earn its allowed return, and has an effect on incentives for efficiency.

Minnesota law provides for substantial mitigation of regulatory lag for rate increases compared with many other states. Utilities in Minnesota control the timing and frequency of their rate case filings. Utilities may use forecasted test years, allowing projected cost increases to be reflected in rates. The utility is entitled to implement interim rates within 60 days of filing a rate case, and those rates are in effect until new final rates are implemented as a result of the rate case. Interim rates are essentially a "make-whole" concept, allowing utilities to reflect cost increases for costs of the same nature and kind and the same rate of return allowed in the most recent rate case, with some exceptions for "exigent circumstance". Also, the Commission must issue a final order within a statutorily defined period.[5]

The extent of lag between changes in cost conditions and a correspondingly adjustment in rates is affected by whether costs are increasing or decreasing. There is likely to be more regulatory lag when a utility is over-earning. Utilities in Minnesota are under no obligation to file, and have not filed, rate cases asking for *decreases* in rates. The Commission can require a utility to

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[4] Part of this time is occupied by management's decision-making process about when to file a rate request. The rest is due to the time required for administrative proceedings before the regulatory body. These will vary by state.

[5] Minn. Stat. §216B.16, subd. 2(a) sets a 10 month due date for Commission action. Minnesota Laws, 2009, Chapter 110 amended Minn. Stat. §216B.16, subd. 2(f) to allow the Commission to extend the period for a total of 90 additional calendar days.

file a rate case if the Commission believes the utility's rates may be unreasonable,[6] but it is a lengthy process. First, the Commission needs to have information about the utility's earnings on a Minnesota jurisdictional basis; the most accessible sources of such information are the annual reports utilities file on May 1 of each year for the previous calendar year, already a lag in information. Then the Commission must (on its own motion or at the request of the OES or others) conduct an earnings investigation, including a hearing process. After the investigation and hearing process, if the Commission finds it warranted, it can require the utility to initiate a rate proceeding; but under statute, the Commission must allow the utility at least 120 days to make the rate filing. It is unlikely that the utility would request a decrease in rates in its mandated rate filing, and if any decrease is warranted, it would only happen after the full 10-13 month rate case process.

Background – Alternative Cost Recovery Mechanisms

The principle of "reasonable opportunity to recover costs and earn the authorized return" may be eroded if cost factors between rate cases change *dramatically* and *unpredictably,* are *substantial in magnitude,* and are due to factors that are *beyond the control* of the utility. For such situations, it may be appropriate to allow outside-of-rate-case mechanisms under which costs can be tracked, and potentially recovered, without requiring a rate case to be filed.

Special cost recovery mechanisms allow a utility to recover its actual costs for a specified function on a periodic basis *outside* the context of a formal rate case. They generally involve a method for tracking specific cost categories, coupled with some form of flexible rate adjustment mechanism (e.g., a rate rider) to generate the required revenues. These special mechanisms are variously referred to as automatic adjustments, cost trackers, and rate riders; while there are technical distinctions that can be made between these terms, this report will use them more-or-less interchangeably.

Special cost recovery mechanisms have been used for purchased gas and electric fuel costs for many years in most states. In Minnesota, these are the Purchase Gas Adjustment (PGA) for the commodity cost of natural gas, and the Fuel Clause Adjustment (FCA) for the commodity cost of fuels used to generate electricity; e.g., coal, natural gas, uranium (Minn. Stat. §216B.16, subd. 7). Use of fuel cost recovery mechanisms helps assure reasonable rates by providing an efficient means of adjusting required revenues to sustained and dramatic changes in fuel costs. Without a special recovery mechanism, frequent rate filings might be needed to ensure that rates cover the reasonable cost of providing reliable service.[7] In addition, financial market ratings could be adversely affected in the case of sustained and dramatic fuel cost increases,

[6] Minn. Stat. §216B.17, subd. 1 and 8.

[7] As CenterPoint Energy pointed out in its comments for this inquiry: "absent a PGA [Purchase Gas Adjustment], even a 10 percent over recovery of gas costs could potentially double an LDC's [Local Distribution Company] net income, while a 10 percent under recovery of gas costs could potentially eliminate an LDC's entire net income." Comments of CenterPoint Energy, Docket No. E,G-999/CI-09-1338, page 2.

thereby increasing financing costs.[8] The PGA and FCA also require that *decreases* in costs be passed along to consumers in a timely manner.

When the PGA and FCA were established in Minnesota in the mid-1970s, both wholesale natural gas commodity and transportation rates were federally regulated; therefore the rates paid by local distribution utilities were largely outside their control. Natural gas commodity rates have since been deregulated, and may be subject to greater fluctuation. The electric market has changed significantly since FCAs were first established, especially with the advent of the wholesale energy market established by the Midwest Independent System Operator. The Commission and other stakeholders are continuing to evaluate whether changes are needed to current FCA mechanisms to reflect these market changes.

In recent years, utilities have increasingly sought special cost recovery mechanisms for various types of expenditures beyond just fuel costs. These were prompted by the imposition of policy mandates, as well as the desire to recover very large capital expenditures for single projects (or a group of related projects)[9] or to simply encourage certain types of expenditures. Since the establishment of the PGA and FCA in 1974 in Minnesota, the following cost recovery mechanisms have been established in statute:

- Conservation improvement/incentives (Minn. Stat. §216B.16, subd. 6b)
- Performance-based gas purchasing adjustment (§216B.16, subd. 7a)
- Transmission cost adjustment (§216B.16, subd. 7b)
- Transmission asset transfer (§216B.16, subd. 7c)
- Low-income electric discount (§216B.16, subd. 14)
- Demand Side Management financial incentives (§216B.16, subd. 6c)
- Natural gas utility infrastructure (§216B.1635)
- Renewable energy power purchase agreements/investment/Renewable Development Fund (§216B.1645, subd. 2)
- Utility owned renewable facilities (§216B.1645, subd. 2a)
- Settlement – Mdewakanton Prairie Island (§216B.1645, subd. 4)
- Emissions reduction rider (§216B.1692, subd. 3)
- Mercury emission reduction (§216B.683)
- Real and personal property taxes (§216B.241, subd. 2b)
- Reliability Administrator (§216C.052)
- Gas Affordability Program costs (§216B.16, subd. 15)
- Electric infrastructure costs (§216B.1636)
- Greenhouse gas infrastructure (§216B.1637)

[8] For example, Interstate Power cites a recent report by Standard and Poor's which states: "[Standard & Poor's] views rate recovery mechanisms that allow for the timely adjustment of rates to changing commodity prices and other expenses, outside of a fully litigated rate proceeding, as beneficial to utility creditworthiness." S&P Research: "Recovery Mechanisms Help Smooth Electric Utility Cash Flow and Support Ratings," March 9, 2009.

[9] For example, Xcel's Metropolitan Emissions Reduction Program.

- Decoupling (§216B.2412)
- Central Corridor utility zone cost adjustment (§216B.16, subd. 7d)

The costs covered by many of these recovery mechanisms are substantially smaller in magnitude than fuel costs and, therefore, they do not fit as neatly the theoretical rationale for special recovery mechanisms. The common denominator in the more recent additions was a perceived need to remove disincentives to investment in areas where the pure economics were asserted to be not singularly compelling, but which, nevertheless, advanced public policy goals; e.g., renewable generation, emission reduction.

Although special recovery mechanisms can help assure reasonable rates in certain circumstances and, when used properly, can provide immediate and cost-specific price signals to utility customers, which (again, in theory) should lead to better consumption decisions, there are concerns with their use. For example, their use can have an adverse affect on incentives. By eliminating regulatory lag and allowing immediate pass-through of certain types of cost increases, meaningful and binding incentives to control costs could be substantially eroded. Contrast this with business entities that are not protected from competition by regulation but are subject to robust competitive pressures. These entities have little or no ability to pass through cost increases, but must constantly find ways to cut costs to stay competitive. In addition, the greater the number of cost categories subject to automatic recovery, the greater the effect on cost containment incentives. The OES noted in its comments that Minnesota utilities have, in fact, pushed for expedited review of special recovery mechanisms, and have opposed measures that would help ensure that costs are reasonable, like competitive bidding or holding utilities to their own cost projections.[10]

In addition, allowing automatic cost recovery in some functional areas but not others could also create contrary incentives for cost-minimizing activities. For example, allowing automatic recovery for fuel might also create an incentive to postpone maintenance of plant, for which there is no automatic recovery. In other words, it may be more profitable to simply burn more fuel than to make plants operate more efficiently. Moreover, selective allowances like this one for fuel could create an incentive to characterize as many costs as possible as "fuel" in order to obtain automatic recovery.

Special cost recovery mechanisms can be very effective for incentivizing investment in certain technologies. That phenomenon is well understood and, in fact, has been employed strategically in recent years to accomplish public policy goals. However, as a practical matter, the need for special recovery seems to have been asserted only for cost categories that were expected to *increase*, with little or no provision for any savings or sharing of benefits that might also result from such investments and without consideration of the utility's actual earnings level. In fact, these mechanisms have been sought with no demonstration offered of the financial implications to be expected in the absence of the special mechanisms, or how the

[10] Comments of the Minnesota Office of Energy Security, Docket No. E,G-999/CI-09-1338, page 5.

mechanisms serve the public interest and not just the financial goals of the company. Finally, given the proliferation of trackers now available and in use, the amount of time required to track and manage each special recovery mechanism has become considerable; certainly for regulators, and presumably for utilities.

Automatic cost recovery mechanisms are increasingly popular, but there are other options for encouraging investments that support public policy or state energy goals. Those alternatives will be discussed in more detail below.

IMPACT ON RATES:

As noted, under certain cost conditions, use of special recovery mechanisms can eliminate the adverse effects of regulatory lag and help assure reasonable rates. If costs are largely outside the control of the utility, are unpredictable and volatile, and are substantial and recurring, it is less likely the utility will have a reasonable opportunity to recover prudent costs and will, therefore, incur added financial risk. The use of special recovery mechanisms under these conditions will help to avoid the cost of the frequent rate proceedings needed to adjust rates to changing conditions and, possibly, help to limit financing costs by dampening the financial risk to the company. In other words, use of special recovery, in certain circumstances, should help to ensure that rates reflect the true cost of providing the utility service.

The probable impact of special cost recovery mechanisms in practice is less clear. As noted, they inherently create the potential for unproductive incentives. For example, even the use of automatic adjustment for fuel costs can create an incentive to include other cost factors in the definition of "fuel." In Minnesota the FCA mechanism has been expanded to include other categories of costs, including, performance-based gas purchasing programs (Minn. Stat., Chapter 216B.16, Subd. 7a), transmission costs (Minn. Stat., Chapter 216B.16, Subd. 7b); and greenhouse gas infrastructure costs (Minn. Stat., Chapter 216B.1637), to name a few.

The risk to incentives is especially significant when special recovery is allowed for cost categories that do not inherently pose a danger of severe financial risk; i.e., costs that are *not* always outside the control of the utility, unpredictable or substantial. In those instances, allowing automatic recovery would also be expected to erode incentives for cost control.

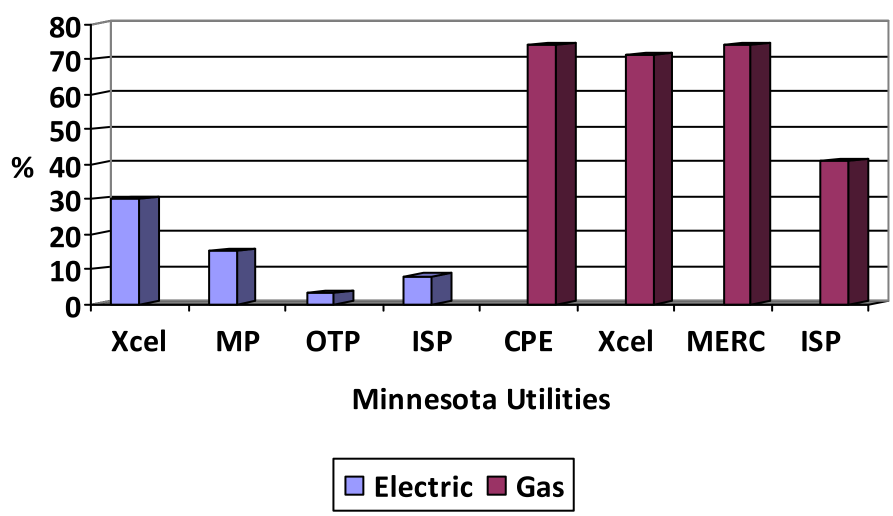
Moreover, making certain cost categories subject to automatic recovery removes them from inclusion in the overall review of costs (those that decrease as well as those that increase) when a general rate case is ultimately filed. It effectively takes them "off the table" in a rate case review and thereby constricts the Commission's rate-making authority. And while special recovery will have the effect of dampening the magnitude of rate requests that utilities make when they do ultimately file a rate case petition, the reality is this effect merely masks the full rate implications for ratepayers.

Attempting to quantify the impact of special cost recovery mechanisms on rates compared to traditional cost recovery mechanisms is not a simple, straight-forward process. The primary method used here is to determine the jurisdictional operating revenues produced by the automatic cost recovery mechanisms utilized by Minnesota's utilities and evaluate their general impact on utility financial conditions.

Appendix A shows, for each cost tracker currently allowed in Minnesota, the amount of revenue each utility collected in 2009, which is the most recent year for which full company information is available.. Appendix A shows that revenues collected under the fuel-related recovery mechanisms far surpass all other automatic recovery mechanisms combined, representing 90% of all revenues collected by automatic recovery mechanisms in 2009. The next largest tracker mechanism is the long-standing mechanisms for Conservation Improvement Program (CIP) costs, which collected 4.8% of total tracker account revenues in 2009. The trackers for emissions reductions and renewable energy power purchase agreements (PPAs) were a distant third (with 1.6%) and fourth (with 1.1%). In other words, the revenues generated by Minnesota's more recent special recovery mechanisms (i.e., other than for fuel and CIP) accounted for less than 3% of the total revenue collected in 2009.

Because the commodity cost of gas is significantly larger than the cost of distributing it to customers, gas utilities inherently recover a larger percentage of revenues through the fuel recovery mechanism. For example, approximately 74% of the 2009 Minnesota jurisdictional revenue for CenterPoint Energy (CPE) was collected via fuel recovery mechanisms compared to 3% for Otter Tail Power (OTP). Figure 1 provides a comparison of fuel recovery revenues as a percent of 2009 annual Minnesota jurisdictional revenues for electric and gas utilities.

Figure 1 Fuel Recovery Revenues as % of Total Company Revenues - 2009



Although both electric and gas utilities use the special recovery mechanisms for fuel and CIP, most of the more recent mechanisms are geared for electric utilities and, therefore, electric utilities use more special recovery mechanisms compared to gas utilities. Among electric utilities, Xcel utilizes the most special mechanisms. In 2009, Xcel's Minnesota electric utility collected approximately $74 million through the automatic adjustment mechanisms.[11] This $74 million represented less than 1% of the utility's total jurisdictional revenues. Minnesota Power collected approximately $29 million in 2009 through the mechanisms for transmission costs and emissions reduction; i.e., 4% of its jurisdictional revenues. Otter Tail Power collected approximately $6 million through the mechanisms for renewable energy PPAs; i.e., also about 4% of its revenues. By contrast, the revenues collected in 2009 through these non-fuel and non-CIP recovery mechanisms by Minnesota *gas* utilities averaged 0.3% of their total revenues. So even though electric utilities utilize more of these more recent mechanisms and collect a larger amount of revenues than gas utilities through their use, the financial impact of these more recent recovery mechanisms is still small for both electric and gas utilities.

Another dimension to the effect of automatic recovery mechanisms on rates is the amount of time spent by utilities and regulators to manage the various cost tracker mechanisms. Time spent to manage these projects translates to regulatory costs which are recoverable in rates.

The Commission has had 679 filings involving one or more of the various automatic cost recovery mechanisms since 2005; beginning with 51 in 2005 and including 147 in 2009.[12]

Figure 2 Number of automatic recovery filings since 2005

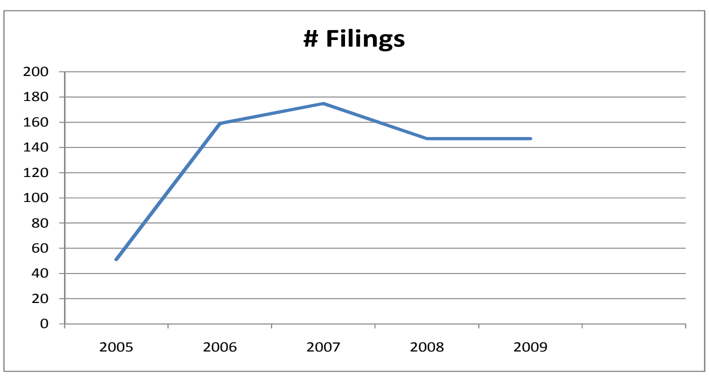


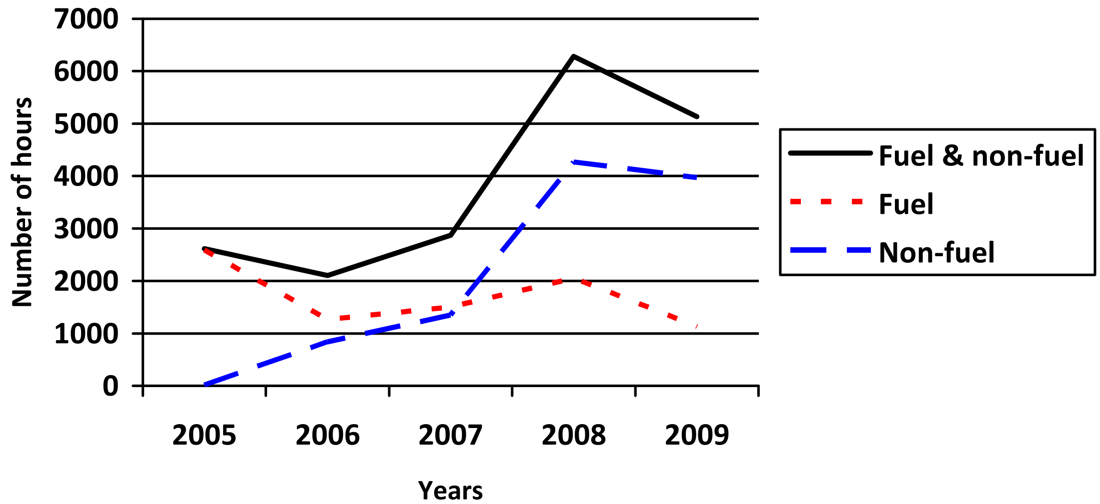
Figure 3 shows that this sustained increase in filings was driven by non-fuel recovery mechanisms. Figure 3 also slows that the amount of time spent by PUC and OES staff and

[11] For transmission costs, greenhouse gas infrastructure, renewable energy PPAs/investment/Renewable Development Fund, emissions reduction, and reliability administrator support

[12] 2007 had the largest number of such filings during this period with 175.

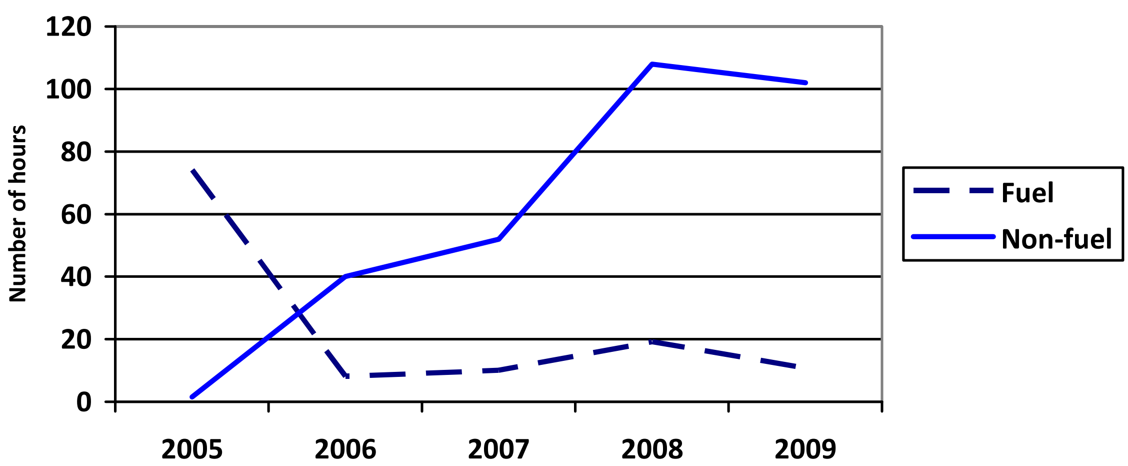
commissioners on fuel-related mechanisms remained relatively flat over this period, while the time spent on non-fuel mechanisms has increased significantly.

Figure 3 Hours Spent by PUC & OES staff on Automatic Recovery Filings



Not only are there more non-fuel-related filings, but these filings are also taking more time to complete. Figure 4 shows that the average number of hours spent by PUC and OES on non-fuel-related filings has greatly exceeded the average time spent on fuel related filings.

Figure 4 Average Hours on Fuel-related vs. Non-fuel-related



However, the prevalence of numerous special recovery mechanisms has not markedly reduced the number of rate case filings. Since January 1, 2005, the Commission has had 18 new rate case filings; i.e., an average of 3 new rate case filings per year. This contrasts markedly with rate case activity in the 1990s and early 2000s, when one filing per year (or less) was the norm.[13] It is noteworthy that most of the non-fuel-related recovery mechanisms have been adopted since that "quieter" time. And although rate cases require a large commitment of resources for both regulator and regulated, the cumulative requirements of those more recent special recovery mechanisms have grown in magnitude and now constitute a major source of activity for the PUC and OES.[14]

These trends confirm that utilities have become much more active in recent years in seeking general rate increases as well as recovering more revenues automatically through automatic recovery mechanisms. However, whether rates are higher or lower because of the existence of special recovery mechanisms remains a difficult question to answer precisely.

It seems very likely that the number of rate case filings as well as the dollar amount of individual rate case requests since 2005 would have been even greater in the absence of *any* automatic recovery mechanism. Certainly special recovery for fuel costs has mitigated the number of rate case filings. And because the fuel cost recovery process adjusts for *decreases* as well as *increases*, unlike the other mechanisms, its use provides a more accurate tracking of fuel costs over time and, therefore, a better price signal to end-users. On the other hand, as noted earlier, use of special recovery mechanisms can also divert certain costs from the rate case process and therefore can mask the true impact on ratepayers. There are other concerns as well.

The availability and use of a special recovery mechanism lightens utilities' responsibility to manage the risk associated with the specific cost category and shifts some of that burden to ratepayers. In theory, this would be expected to erode incentives for efficiency and cost control, creating upward pressure on rates. Whether that is true and the extent of the impact on rates remains unmeasured under the current array of mechanisms. Adding specific performance requirements and providing an enforcement mechanism would be a means to limit such adverse effects on incentives.

Because special recovery mechanisms have the effect of transferring risk away from utility shareholders, their use is viewed favorably by the financial markets and, theoretically, should result in a lower cost of capital for the utility and, thus, help relieve pressure on rates. However, Minnesota utilities are not required to demonstrate any such effects and it is not clear the extent to which any savings are, in fact, shared with ratepayers.

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[13] Factors contributing to the increase in rate case activity include increasing state public policy requirements (e.g., renewable energy, emission reduction, energy efficiency), a federal policy shift to greater integration of transmission services at the regional level along with critical transmission infrastructure upgrade demands, and the downturn in the economy in general.

[14] As of 2009, special cost recovery filings required approximately 5,000 hours of PUC and OES time, compared to approximately 11,000 hours for rate cases during the same period.

CUSTOMER UNDERSTANDING:

The issue cited by most ratepayers who express concern about their utility bills is the *total* amount of the bill and how that obligation fits within their budget. In addition, customers occasionally question whether the amount they must pay represents fair value for the service they receive. Ratepayers clearly regard utility expenditures as an important outlay, but one of several necessary outlays. For most, their awareness of the differences between utility prices versus other goods or services focuses on why utilities are allowed to operate in a monopoly setting when other businesses are not; and why the utility does not manage its charges for services within the set rates they are granted, rather than those base amounts plus cost recovery charges.

Although ratepayers' specific awareness of the use of special recovery mechanisms is relatively low, the Commission has, in recent years, received questions and comments from a small but growing number of ratepayers about the additional charge types that have appeared on their bills, many of which are due to special recovery mechanisms. These concerns focus on complexity of the bill, as well as opinions (pro and con) on the merits of the underlying public policy prompting the charge. The occurrence of these ratepayer contacts seem to have been contemporaneous with the implementation of special recovery mechanisms. Ratepayer reaction would be expected to be related to the number of special mechanisms employed and the amount of revenue collected through their use; i.e., were the number of mechanisms and/or the amount of revenue thus collected to increase, we would expect to see a corresponding increase in ratepayer contacts.

Since customers generally are not engaged on these more nuanced issues of special cost recovery, greater public attention to the implications of their use alone may not ensure the protection of ratepayer interest. Consequently, sharing with ratepayers the efficiency gains resulting from special recovery measures should be an element of special recovery mechanisms.

ALTERNATIVES:

The use of automatic cost recovery mechanisms has been expanded in recent years in response to utility claims about the effects of increased uncertainty and heightened concerns that regulatory lag leads to financial effects for utilities that are more adverse than favorable. Authorizing the use of mechanisms that help reduce risk for utilities and make it more likely they will have a reasonable opportunity to recover costs and earn their authorized return may not be unreasonable for entities that are called upon to not only provide essential services, but to do so in a manner that addresses pressing policy needs. On the other hand, the expanded use of these mechanisms can lead to reduced efficiency and increased administrative costs, both of which will put upward pressure on rates, as well as contribute to customer confusion.

Therefore, if it is agreed that traditional regulation requires some degree of modification to address more dynamic industry conditions, the question is: Are there viable alternatives?

Special cost-specific recovery mechanisms of the type discussed above are just one type of alternative options for reducing recovery uncertainty for utilities. Other examples include the following:

1. Recovery of construction costs during construction, rather than only after construction;
2. Approval of specific projects in advance of completion (i.e., "pre-approval");
3. "Securitization," which is a government guarantee of cost recovery, intended to reduce financing costs; [15]
4. Some form of Earnings Sharing Mechanism (ESM), which essentially creates one rate-of-return tracker designed to allow adjustments that enable the utility to earn its authorized return all the time.

Construction Work in Progress

Construction Work In Progress (CWIP) is an accounting method for accumulating expenditures related to the design and construction of major facilities before they are completed and put into service. In traditional utility ratemaking, the utility is not allowed to earn a rate of return on these investments until the plant is used and useful in providing utility service. Instead, the financing costs are "capitalized" and become part of the total plant cost included in the rate base on which the utility may earn a return, after the plant is completed and the associated investment and costs are found to be prudent and reasonable in a rate case.

An alternative approach to CWIP is to allow the utility a current return on its investments in major facilities while they are still under construction, either through inclusion in rate base in a rate case, or through a rider mechanism. This technique reduces the risk of non-recovery and aids in cash flow during construction, which may help keep financing costs lower. However, allowing recovery in rates before a plant is completed may not allow for meaningful review of the reasonableness of the total costs of the project and may result in ratepayers paying for facilities that are never completed or that have significant cost overruns.

Current Minnesota law allows the Commission to include CWIP in the rate base upon which the utility earns a return in a rate case under certain circumstances, but the Commission rarely has done so.[16]   Certain rate rider statutes, including those related to utility-owned renewable

[15] For more details, see *Pre-Approval Commitments: When And Under What Conditions Should Regulators Commit Ratepayer Dollars to Utility-Proposed Capital Projects?* The National Regulatory Research Institute, November 2008,

[16] Minnesota Statute, §216B.16, Subdivision 6a, allows the Commission discretion in determining the extent to which income used in determining the actual return for the utility shall include an allowance for funds used during construction.

facilities and transmission, explicitly allow the Commission to permit recovery of CWIP through the rider, and the Commission has generally allowed such recovery. Allowing a current return on CWIP for these types of facilities, and for other major facilities, could instead be done routinely in general rate cases.

Pre-approval

Pre-approval of major projects by regulatory commissions is another method to reduce the risk to utilities, and may be used alone or in combination with allowance of CWIP in rates and/or rate riders. Pre-approval review processes generally involve a determination by the regulatory commission that a project proposed by the utility is reasonable *prior* to starting construction. This gives the utility a reasonable assurance that the costs related to the project, as long as it is prudently managed, will be allowed future recovery in rates. This lowers risk to the utility and may result in an enhanced ability to raise capital at reasonable cost.

A specific pre-approval process for certain environmental improvements became part of Minnesota Law during the 2010 Session. Laws of Minnesota, 2010, Chapter 373 allows a utility to petition the Commission for an advance determination of prudence for a project expected to cost Minnesota ratepayers $10 million or more and which is needed to comply with federal or state air quality standards. The utility may begin recovery of costs that have been incurred for the project, and which are shown to be reasonable and necessary, in the next rate case following the advance determination of prudence. However, the Commission has some discretion on the specific costs to allow, including whether to allow a current return on CWIP during construction.

Securitization

Securitization, as the term is used here, does not refer to the conversion of financial assets into other marketable securities (which has been much in the news of late), but to the granting of a statutory right to cost recovery for utilities in order to avoid "stranded investment" in transition to deregulated energy markets. Securitization, in this sense, was adopted in California and some other states which opted for deregulation of the electric industry in the 1990s. The granting of a statutory right to cost recover eliminated substantial risk for utilities operating in these conditions and did so by shifting that risk to all state *taxpayers* instead of just the company's ratepayers. More recently, some states have allowed securitization to be used to finance major storm recovery efforts, environmental improvements, and discussion is taking place about the possibility of using securitization for Greenhouse Gas (GHG) reduction measures. Such measures have not been enacted, or seriously considered to date, in Minnesota.

An *Earnings Sharing Mechanism*

An Earnings Sharing Mechanism (ESM) would replace the array of special recovery mechanisms with one mechanism based on rate-of-return. [17] Generally, an ESM allows adjustments outside of rate case proceedings for both: (1) actual costs deviating from the level of costs identified in the test year used in the most recent rate case, and (2) actual revenues deviating from test year revenues. [18] However, an ESM would constitute a *major change* from traditional rate-making, and were a version of an ESM to be pursued in Minnesota, considerable attention would need to be devoted to preserving equity and avoiding unnecessary additional pressure on rates.

An ESM can take different forms. In general, rates are initially set in a rate proceeding and then, pursuant to some sort of review of costs, revenues, and earnings, adjustments would be allowed periodically to achieve certain targets. Typically, an ESM would target a certain rate of earnings, i.e., an authorized rate of return as established in a full rate case. Ideally, an ESM would also involve a return on equity band (ROE band), which is a range around the authorized rate of return. With an ROE band, no automatic rate adjustments are allowed as long as the overall earnings are within the band, but would be permitted if earnings are outside the band. For example, if 10-14% is set as the ROE band around the authorized rate of return of 12%, then rates could be adjusted upward if the actual return falls below 10%. The adjustment could be geared to increase the return closer to the minimum level specified in the ROE band, i.e., 10%. Conversely, rates could be adjusted downward to address actual earnings above the band. [19] As noted, these adjustments would occur through some form of regulatory review, but without full rate case review.

An ESM has advantages and disadvantages. As noted, its use can substantially reduce the need to administer numerous separate recovery mechanisms. Also, use of an ESM should reduce the frequency of rate cases and could result in rates that more closely coincide with changing market developments. In addition, unlike the special recovery mechanisms which track only single cost categories to the exclusion of everything else, an ESM would take into account the utility's overall profitability in adjusting rates.

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[17] *How Should Regulators View Cost Trackers?* National Regulatory Research Institute, September, 2009. Page 11. Some specific examples include: Oklahoma Performance Based Rate Change Tariff; North and South Louisiana Rate Stabilization Plan; Texas Cost of Service Adjustment. In addition, the Federal Energy Regulatory Commission employs formula rate plans for transmission ratemaking.

[18] An ESM should not be confused with decoupling. Decoupling, as it is defined in Minnesota statute, is "a regulatory tool designed to separate a utility's revenue from changes in energy sales. The purpose of decoupling is to reduce a utility's disincentive to promote energy efficiency." Minnesota Statutes, § 216B.2412. Decoupling is focused on changes in sales and is a form of a cost tracker. An ESM is typically focused on *overall earnings*; i.e., accounting for changes in all costs and all revenues.

[19] How the rate adjustments would occur and their specific magnitude would be factors in the design of the specific plan. For example, should the target of an upward adjustment be the authorized return or the minimum of the ROE? Likewise, should downward adjustments be set as "dollar-for-dollar" reductions for ratepayers or should some of the extra gain be provided the utility as a reward for good performance? Also, how often should adjustments be allowed? Should they affect all rates?

However, compared to traditional ratemaking, where rates remain fixed between rate cases, an ESM would diminish regulatory lag, which would be expected to *reduce* the incentive of a utility to control its costs between rates cases.[20] This potential effect is particularly acute if *all* cost categories are amalgamated into, essentially, one cost recovery mechanism under the ESM. As one authority put it, use of an ESM of this nature effectively puts the utility's future on "auto-pilot."[21] Also, as noted earlier, an ESM shifts a larger share of risk to ratepayers. Frequent rate adjustments will have an impact on customers, and that impact is more likely to be negative if the adjustments are always (or usually) increases. Customer confusion is also likely to be a factor, but may be offset somewhat by very deliberate informational campaigns.

There are methods to mitigate some of the adverse effects of an ESM. For example, limiting expedited rate adjustments to only those instances when *major* cost items (e.g., fuel and purchased gas) lead to earnings outside the authorized band is a way to curb adverse affects on incentives, rate volatility, and the degree of risk shift. Adverse effects on incentives could be further mitigated by requiring that the utility demonstrate prudence and provide reasons why specific cost items were higher than their test year levels.

ESM's can occur in various forms. In stakeholder comments received pursuant to the Commission's January 29 meeting on this topic, some examples were cited. One option was Formula Rate Plans (FRP). The main distinguishing feature of an FRP is the use of a specific formula to calculate automatic rate adjustments targeted to yield a predetermined ROE, given real-time changes in certain cost factors. The formula by which any rate adjustments are calculated is derived and approved as part of a general rate case proceeding. With an FRP, utilities are required to provide information periodically on the various cost and revenue factors accounted for in the formula.[22] Because the formula has been approved in advance, the periodic regulatory review is confined to scrutiny of the prudence of particular input items or to arguments that the utility has misapplied the formula.[23] However, any costs subject to an independent tracker or rider would not be included in the FRP process. For example, if it was determined that fuel costs should continue to handled via an independent automatic adjustment mechanism, these costs would not be included in the FRP formula. Appendix B provides detailed descriptions of various formula rate plans currently in effect in some other jurisdictions.

[20] It should be noted that as long as the utility's rate of return is within the "band" there would be some incentive for cost control. If it operates within that band, it has an incentive to control costs to maximize its actual return because its rates will not be changed. The difference with an ESM is that rates won't remain unchanged until the next rate case, but would be changed if there is a showing of some combination of change in costs and/or revenues that cause the actual return to fall outside the band. So the incentive would be similar to traditional rate-making but not as binding.

[21] Ken Costello, *The Two Sides of Cost Trackers: Why Regulators Must Consider Both*, the National Regulatory Research Institute. Statement made as part of a webinar on October 27, 2009.

[22] This could be cost data from the accounts of costs and revenues filed with the Federal Energy Regulatory Commission on the annual FERC Form 1.

[23] The National Regulatory Research Institute, November 2008, *op. cit.*, page19

Another variation is the Multi-Year Rate Plan (MYRP). As with FRPs, a MYRP is established and approved within the framework of a traditional rate proceeding. However, rather than allowing rate adjustments in response to changed conditions, the MYRP locks in specific future rate adjustments based on forecasts of future conditions made during the basic rate proceeding. A predetermined rate adjustment is established for each year of the MYRP's term (usually 3 to 5 years) based on future test-year revenue requirements or some sort of index, e.g., based on growth. Once a MYRP is established, rate case filings are prohibited during its term.

MYRPs rely extensively on accurate forecasting of critical cost and revenue factors. Once approved, parties must live within the specifications of the plan as it is defined which could be difficult in periods of dramatic, unexpected changes. However, MYRP can also employ earnings sharing provisions that require a utility to return earnings beyond an ROE threshold during the term of the plan. As with FRPs, costs tracked independently are typically not included in a MYRP. Appendix C provides the details of a MYRP for Consolidated Edison in New York.

IMPROVE ADMINISTRATION AND UNDERSTANDING

The final requirement of Minnesota Laws 2009, Chapter 110, section 33, is an evaluation of ways to better utilize automatic cost recovery mechanisms; i.e., how to make the current array of special recovery mechanisms operate more efficiently. Given the large number and diverse array of such mechanisms currently available and in use in Minnesota, greater efficiency in their use would require significant change. At a minimum, there needs to be a focus on reducing administrative costs and making greater provision for ratepayer sharing efficiency gains.

Three possible fundamental approaches set the continuum for further discussion; each approach has advantages and disadvantages. The three approaches are set forth below:

1. Eliminate all existing trackers that cannot demonstrate extreme financial consequences, and provide for a reasonable opportunity for cost recovery for everything else through rate case proceedings.
2. Consolidate all trackers (except, perhaps, fuel) into one overall tracker and develop a form of comprehensive ESM.
3. Substantially reduce the number of trackers to allow only those that are most commonly used, involve the largest financial impact, and incorporate the greatest accountability.

Allow special recovery mechanism only to avoid extreme financial conditions:

This approach would allow cost trackers in only special situations where the absence of a special recovery mechanism would cause *extreme* financial problems; i.e., conditions that would adversely affect customers in the long run. The classic example of such a factor is fuel costs. The National Regulatory Research Institute (NRRI), in its report, *How Should Regulators View Cost Trackers*[24] identifies the benefits of this approach:

a) Using the same cost recovery mechanisms for all utility operations *(i.e., a rate case instead of numerous individual trackers)* to prevent perverse incentives; perverse incentives can lead to a higher cost of service and utility rates.
b) Balancing a utility's total costs and total revenues *(again, through a rate proceeding)*; without this balancing, it is conceivable that the utility could recover one cost item through a tracker, and over recover other costs set in the last rate case to result in the utility earning above its authorized rate of return; a rate case has the attractive feature of matching revenues with costs on an aggregate basis;
c) Strengthening regulatory lag to provide the utility with more motivation to control costs; regulatory lag is an important feature of traditional ratemaking in forcing the utility to shoulder the risk of higher costs between rate cases; and
d) Scrutinizing a utility's costs and performance in different areas of operation; commissions seem to review costs recovered outside of a rate case less thoroughly, with the increased likelihood of customers recovering a utility's imprudent costs.[25]

With this approach, if a utility believes a special recovery mechanism is needed, it would have to *demonstrate* that it is essential to avert a very severe financial condition. This would require a showing of the impact of possible cost futures and an assessment of their likelihood. If the cost factor fits the classic profile (i.e., large in size, volatile, and out of company's control), then it would be a candidate for special recovery. But, as the NRRI points out, "even then, the regulator should consider the adverse incentive effects and how it can compensate for this problem."[26] This assessment could be done by monitoring performance or could include a performance-based incentive in the tracker mechanism.

However, limiting the use of special recovery to only the most severe conditions will make it much more difficult to "surgically" remove disincentives to certain expenditures, which, by themselves may not necessarily carry significant financial consequences, but which are seen as necessary to accomplish certain goals. Limiting special recovery to only circumstances demonstrating severe consequences restores and reinforces regulatory lag. For utilities who claim financial distress because of some cost condition, this approach "holds their feet to the fire" to demonstrate the exception is needed to minimize additional costs and will not harm incentives for efficiency. Although this approach would minimize administrative costs and would provide greater assurance automatic recovery is the exception rather than the rule, it may not offer the flexibility needed in the face of dynamic industry conditions and growing public policy imperatives.

[24] The National Regulatory Research Institute, September, 2009, *op. cit.*, pp. 15-17.
[25] *Ibid.*, p. 16
[26] *Ibid.* pp. 16-17.

Consolidating trackers into a single rate-of-return tracker:

As noted previously, an ESM can assume the role of a "rate-of-return tracker" that, in effect, amalgamates different special recovery mechanisms into a single mechanism. This approach has several noteworthy features. By consolidating all recovery mechanisms, this approach reduces the administrative costs of managing numerous individual recovery mechanisms. By allowing expedited recovery based on overall return, this approach can help address financial risk concerns of utilities.

In addition, basing rate adjustments on overall return instead of changes in a single cost factor, especially if combined with sharing mechanisms, can help ensure greater equity between ratepayers and shareholders.[27] In addition, some of the incentive problems of special recovery mechanisms can be diminished with an ESM that incorporates an ROE band, particularly if coupled with a required showing of prudence if costs exceed test-year levels.[28] Moreover, use of an ESM does not preclude use of special recovery for major cost items that by themselves pose a severe financial risk. In addition, as with any of these approaches, building in specific performance requirements can ensure public policy goals are being adequately addressed.

However, moving to an ESM type of structure represents a *major change* in Minnesota's approach to regulation. As with any such change, the "devil is in the details" and working out those details would be a contentious and time-consuming process. Given the degree of change this would represent, it would be best to limit its initial use to an experimental model, if such a change is deemed necessary. In addition, it may be a "hard sell" to explain to ratepayers the benefits of moving from the current system, which offers utilities an *opportunity* to earn an authorized return (leaving it to them to create the efficiencies required), to a system that would virtually *guarantee* a utility something very close to its authorized return with greatly reduced business risk. Consequently, there would have to be very obvious and ample provision for ratepayer benefits if such a plan is to be seriously entertained.

Reducing the number of special mechanisms but increasing accountability:

Generally, this option would aim to reduce the number of available special recovery mechanisms to only those most commonly used by utilities and involving significant financial impact. This option should also seek to consolidate remaining recovery mechanisms to save administrative costs, as well as incorporate specific performance metrics, authority to enforce requirements based on those metrics, and provisions for sharing savings with ratepayers.

[27] An ESM could allow recovery of increased costs but only if the utility was already earning a "low" rate of return (i.e., below the ROE band).
[28] As noted earlier, as long as the utility's rate of return is within the "band" region, it has some incentive for cost control, though arguably not as great as under traditional rate-making.

Although they were not necessarily advocating for this particular approach, the OES suggested a number of requirements to improve accountability and equity in the use of out-of-rate case recovery mechanisms. These suggestions provide excellent examples of the kind of new requirements that should be considered in any change in Minnesota's approach to special recovery mechanisms. The following is the list offered by the OES:

a) Requiring utilities to use a robust competitive bidding process to acquire new facilities;
b) Requiring a utility to justify why it would be in the public interest to recover costs of a project before the facility is used and useful;
c) Requiring utilities to share with ratepayers new sources of revenue obtained through resources paid for by ratepayers;
d) Not allowing utilities to recover costs through a rider above the amount the utility initially indicated the project would cost;
e) Not allowing deferred accounting for any cost overruns (utilities could request recovery of any such cost overruns at the time of a subsequent rate case; however, it should be clear that the burden of proof is on the utility to show how any such additional cost recovery should be reasonable to allowing rates);
f) Putting utilities on notice that the Commission may modify or cease the amounts recovered in riders if facilities do not perform as proposed or for any other reason necessary to protect the public's and ratepayer's interest, consistent with general ratemaking principles.[29]

The main advantages of this approach are the potential for lower administrative costs, greater accountability and sharing of benefits without the more dramatic changes associated with the other two options. The main problem with this hybrid approach is that it preserves the use some individual special recovery mechanisms with all the inherent risks to incentives that entails as well as administrative costs. Although administrative costs would be expected to be diminished through the reduction in the number of special mechanisms, building in performance standards and compliance, as well as provisions for sharing of benefits, would require administrative time. So the ultimate net impact on costs is difficult to gauge with a high degree of certainty. However, it seems likely that even if the overall costs were higher, the value delivered to end-users would be markedly greater by virtue of these additional measures.

CONCLUSIONS:

Minnesota Laws 2009, Chapter 110 posed four basic questions to be addressed by this report. The following is a restatement of those questions with a brief response summarizing the main finding of the report.

[29] Comments of the Minnesota Office of Energy Security, Docket No. E,G-999/CI-09-1338, page 5.

Question: Are rates higher or lower as a result of the special recovery mechanisms we have seen in Minnesota?

Answer: This cannot be precisely measured. However, it seems very clear that recovery mechanisms for fuel-related costs have helped to curb upward pressure on rates. The rate impact of recovery mechanisms for items other than fuel is far less clear, but there is concern that they may contribute to upward pressure on rates. Almost all of the mechanisms enacted since the PGA/FCA have been to allow accelerated recovery of costs that are increasing.

Question: Has customer understanding of utility rates been enhanced or diminished as a result of these special recovery mechanisms?

Answer: Generally, customers are more concerned about their total utility charges and how those fit within their income and other expenses than with what components comprise those charges. However, while the questions and comments of customers that have been raised with the Commission regarding special recovery charges have been relatively few, they have been growing over the last several years. Given this timing, there may be a correlation with the recent increase in the type and overall number of special recovery mechanisms. Since customers generally are not engaged in these issues, greater public attention alone will not ensure the protection of ratepayer interest. Consequently, sharing of efficiency gains with ratepayers should be an element of special recovery mechanisms.

Question: Are there alternatives that should be considered?

Answer: There are alternatives to the array of special recovery mechanisms currently in effect in Minnesota. There are advantages and disadvantages to each. All would afford utilities protection from risk beyond that afforded by the franchise monopoly they currently possess. All tend to shift risk from the utility to ratepayers.

Question: Are there ways to make the current system work better?

Answer: The current system of numerous special recovery mechanisms has become cumbersome, raises concerns about cost control, and has constrained the Commission's primary ratemaking instrument, the general rate case. Improving the current system will require adjustments to ensure greater accountability and a sharing of benefits with ratepayers. Fundamentally, the question is whether there are better ways to incentivize utility performance to ensure public policy goals are met. There are alternatives and they each should be evaluated through further discussion and inquiry.

The major thrust of the answers to these questions, and of this report in general, is that a fundamental reassessment of the current use of special recovery mechanisms is in order. This report is intended to provide a foundation for that reassessment and, hopefully, some structure for moving forward. The Commission believes there is need for continued dialogue among legislators, utilities and other stakeholders about the alternatives presented here and about possible future steps. We look forward to having that discussion.

APPENDIX A

Attachment A
Special Recovery Revenues for 2009

Recovery Mechanism	Xcel	Xcel	Minnesota Power	Otter Tail Power	CPE	MERC	IPL	IPL	Total $ Collected via Special Recovery	Percent of Total
	Electric	Gas	Electric	Electric	Gas	Gas	Electric	Gas		
Fuel Clause Adjustment	897,636,663	404,965,958	103,943,736	3,636,051	744,436,000	208,556,332	5,800,326	5,612,984	2,374,588,050	90.7%
Conservation improvement program costs	107,129,850	(807,811)	1,537,666	963,403	13,283,000	1,942,314	1,120,089	218,302	125,386,813	4.8%
Real and Personal Taxes (Energy Conservation)		57,680							57,680	0.0%
DSM financial incentives									-	0.0%
Performance-based gas purchasing adjustment									-	0.0%
Transmission cost adjustment	13,853,522		1,372,565						15,226,087	0.6%
Transmission asset transfer									-	0.0%
Central Corridor utility zone cost adjustment									-	0.0%
Low-income electric discount									-	0.0%
Gas Affordability Program costs		2,596,975			5,010,000	1,027,829		42,550	8,677,354	0.3%
Natural gas utility infrastructure									-	0.0%
Electric infrastructure costs									-	0.0%
Greenhouse gas infrastructure	20,588,114								20,588,114	0.8%
Renewable energy PPAs/investment/Renewable Development Fund	22,129,492			5,954,349					28,083,841	1.1%
Utility owned renewable facilities									-	0.0%
Settlement – Mdewakanton Prairie Island									-	0.0%
Emissions reduction rider	15,266,776		27,618,749						42,885,525	1.6%
Decoupling									-	0.0%
Mercury emission reduction									-	0.0%
Reliability Administrator	$ 2,116,321.00								2,116,321	0.1%
Total	1,078,720,738	406,812,802	134,472,716	10,553,803	762,729,000	211,526,475	6,920,415	5,873,836	2,617,609,785	100.0%
% of total $ collected via special recovery in MN	41.2%	15.5%	5.1%	0.4%	29.1%	8.1%	0.3%	0.2%	100.0%	
Annual company jurisdictional revenue	$ 3,042,238,369	$ 573,316,174	$ 681,800,000	$ 150,124,000	1,010,225,969	$ 280,655,214	$ 73,300,000	$ 13,600,000	$ 5,825,259,726	
$ collected by company via all special recovery mechanism as % to total company revenue	35.46%	70.96%	19.72%	7.03%	75.50%	75.37%	9.44%	43.19%		
$ collected via Fuel Clause Adjustment as % of total company revenue	29.51%	70.64%	15.25%	2.42%	73.69%	74.31%	7.91%	41.27%		

APPENDIX B

Cleco Power Formula Rate Plan (Effective since 2010)

Item	Description
Formula Rate Plan (FRP)	Cleco Power has a formula rate plan in place starting in 2010 and is effective until 2013. Based on an annual review of total revenue requirements, all rates are adjusted (+/-) on a cost per kWh basis to reflect a ROE shortfall or over achievement in previous year.
Similar FRP Plans	There are formula rates in place for other utilities in Louisiana such as Southwestern Electric Power and Entergy. Formula rates are also in place in Mississippi and proposed in Arkansas and Texas.
FRP Structure	Starts with a full rate case proceeding to set the rate baseline which was just approved in October 2009 to be effective done in 2010. In each of the four years following the baseline case, there is an annual revenue review and monitoring of the company's revenue requirement, through an annual filing of a pre-approved formula worksheet. The rate base is adjusted annually to account for additions, subtractions, and depreciation. Rate design and cost allocations do not change, and any increase/decrease is distributed equally across all customer types.
FRP Filing Process	On or before October 31, the utility completes the annual formula rate form using actual data from July 1 to June 30 (i.e. 2010's October filing will have data from July 1, 2009 to June 30, 2010) that contains rate base, cost of capital, other revenues, utility expenses, depreciation, and taxes. Interested parties have until 60 days to review, and provide a recommendation. Company will work with interested parties to complete reviews within six months of filing date. At the conclusion of this period a report will be filed outlining any outstanding issues. Thirty days after this report, staff will file a final report that includes all unresolved issues. See Disputes section if all issues are not able to be resolved. FRP rate adjustment becomes effective on or after the first billing cycle in July.
Disputes	Staff reports that do not recommend a refund or incremental cost recovery and are not protested will not require a vote by the commission. If protests arise from the staff report and refunds/incremental cost recovery are not made in the first billing cycle in July then interest shall accrue on any amount ultimately ordered to be refunded by the commission and issued at the time specified by the commission.
Caps/Limits	Earnings sharing provision: Cleco retains all earnings up to an 11.3% ROE. If the ROE is greater than 11.3% and less than or equal to 12.3% then Cleco returns 60% of the earnings above 11.3.% but less than or equal to 12.3% to customers. If the ROE is greater than 12.3% then Cleco returns 100% of the earnings in excess of 12.3% to customers.
Revenue Requirement	Uses actual historical test year. Revenue Requirement is determined by completing the formula rate worksheets.
Return on Equity (ROE)	ROE is litigated and authorized through the original rate case proceeding. Currently 10.70%. The authorized ROE is not modified through the term of the formula rates.
Extraordinary Adjustments	If Cleco experiences an exceptional cost increase or decrease having a net annual effect on its earned ROE of 80 basis points then Cleco will increase or decrease rates to get its ROE to 11.3% or 10.7%. Exceptional cost changes shall be collected or returned to customers as ordered by the Commission. The amount of any exceptional cost change will be reviewed annually.
Adjustments to FRP	Establishes an O&M tracker where certain costs in excess of $25.6MM annually will be deferred until the company's next rate case.
Treatment of Riders	Purchased power capacity costs, environmental costs, and infrastructure projects can be recovered through the FRP. Storm related costs are excluded from FRP calculations.
True-Up Provision	Not necessary since actual historical test year is used
Effective Years	FRP effective in 2010, 2011, 2012 and 2013 based on 12 month actuals from July 1 - June 30. If FRP is not extended then Cleco will be required to file a rate case by October 31, 2014
Regulatory Oversight	FRP does not limit the ability of jurisdictional regulators to call the company in at any time for a full rate review
Benefits of FRP	Achieves certainty by agreeing in advance on the formula for the annual review. Conserves regulatory, company, and intervenor resources because it limits items subject to debate. Avoids the criticism of shifting risk from companies to ratepayers because annual changes are limited to the earnings sharing provision. Supports company's ability to access capital on reasonable terms Reduces the need for frequent, costly, and lengthy rate cases. Promotes price stability through gradual rate changes.

Entergy Louisiana Formula Rate Plan (Effective since 2005)

Item	Description
Formula Rate Plan (FRP)	Entergy Louisiana has a formula rate plan in place since 2005. It was last extended in 2009 and is effective until 2012. Based on an annual review of total revenue requirements, all rates are adjusted (+/-) on a cost per kWh basis to reflect a ROE shortfall or over achievement in previous year.
Similar FRP Plans	Entergy has experience with formula rates in other jurisdictions including: Entergy Mississippi, Entergy Gulf States Louisiana, Entergy Louisiana, Entergy New Orleans, and Entergy Arkansas
FRP Structure	Starts with a full rate case proceeding to set the rate baseline which was done in 2005. In each of the three years following the baseline case, there is an annual revenue review and monitoring of the company's revenue requirement, through an annual filing of a pre-approved formula worksheet. The rate base is adjusted annually to account for additions, subtractions, and depreciation. Rate design and cost allocations do not change, and any increase/decrease is distributed equally across all customer types.
FRP Filing Process	On or before May 15, the utility completes the annual formula rate form using actual data from the prior year that contains rate base, cost of capital, other revenues, utility expenses, depreciation, and taxes. Interested parties have until August 15 to review, and provide a recommendation. Company has until September 30 of the filing year to review, make corrections and/or resolve differences. See Disputes section if all issues are not able to be resolved. FRP rate adjustment becomes effective on or after the first billing cycle in September of the filing year.
Disputes	If differences are not resolved in the FRP Filing Process then company would file dispute with the commission. Then 15 days after a commission order, the company will file revised final adjustment filing and then adjust rates in the next billing cycle. 60 days after final order company will determine amounts to be refunded or surcharged with interest if applicable.
Caps/Limits	1) ROE bandwidth: if the historical actual earned ROE falls outside 80 basis points of the authorized ROE of 10.25% then utility is allowed to recover 60% of the shortfall up to the lower end of the band from ratepayers or refund 60% of the excess to customers if upper band is exceeded ; no adjustment if earned ROE falls within the range 2) a change in rider FRP revenue level will not be made unless it changes the earned ROE by more than 5 basis points
Revenue Requirement	Uses actual historical test year. Revenue Requirement is determined by completing the formula rate worksheets.
Return on Equity (ROE)	ROE is litigated and authorized through the original rate case proceeding. Currently 10.65%. The authorized ROE is not modified through the term of the formula rates.
Extraordinary Adjustments	If the company experiences an extraordinary adjustment in excess of $10 million then either the company or commission may initiate a proceeding to consider a pass-through of such extraordinary cost increase or decrease
Adjustments to FRP	Environmental costs, energy efficiency costs, system agreement case effects, acquisition effects, repowering project effects, generator replacement effects, depreciation/decommissioning rate effects, storm damage accrual effects, and interruptible load case effects are to be considered separately outside the FRP mechanism. Company is allowed to recover through the FRP the revenue requirement associated with purchased capacity costs in excess of base rates and any capacity cost adjustments
Treatment of Riders	Any riders that recover specific costs are eliminated from the FRP calculation and are recovered outside the FRP process. The excluded riders are: rough production cost equalization adjustment rider, non-rough production cost equalization adjustment rider, financed storm cost rider, storm cost offset rider, environmental adjustment clause rider, and green pricing service pilot rider.
True-Up Provision	Not necessary since actual historical test year is used
Effective Years	FRP effective in 2010, 2011, and 2012 based on prior year's numbers
Regulatory Oversight	FRP does not limit the ability of jurisdictional regulators to call the company in at any time for a full rate review
Benefits of FRP	Achieves certainty by agreeing in advance on the formula for the annual review. Conserves regulatory, company, and intervenor resources because it limits items subject to debate. Avoids the criticism of shifting risk from companies to ratepayers because company can only recover 60% of shortfall. Supports company's ability to access capital on reasonable terms Reduces the need for frequent, costly, and lengthy rate cases. Promotes price stability through gradual rate changes.

APPENDIX C

Consolidated Edison Multi-Year Rate Plan (Approved in March 2010)

Item	Description
Multi-Year Rate Plan	Con Ed and interested parties agreed to increase rates at a specific dollar amount each year for the next three years
Similar Multi-Year Rate Plans	Other utilities in New York such as Orange & Rockland, Central Hudson Gas & Electric, and Niagara Mohawk Power either have approved or pending multi-year rate cases. Plus, utilities in California, Maine, and Massachusetts have currently approved multi-year rate cases while Florida utilities had multi-year rate cases that just expired in 2009.
Multi-Year Rate Plan Structure	Con Ed is allowed to recover $540.8MM in 2010, $306.6MM in 2011, and $280.2MM in 2012. However, to mitigate the impact on customers of the first year rate increase, the parties agreed to levelize the increase at $420.4MM each year with the final rate hike to include an adjustment to allow the ongoing rates at that point to equal the rate level that would have otherwise been in place had the rate increases not been levelized.
Caps/Limits	1) ROE is conditioned upon Con Ed reducing O&M expenses by $27MM in 2010, $20MM in 2011, and $13MM in 2012 2) Accrued carrying charges of delivery related capital expenditures is capped at $1.2B in 2010, $1.16B in 2011, and $1.14B in 2012 3) Accrued carrying charges of other capital expenditures is capped at $219.8MM in 2010, $207.3MM in 2011, and $194.9MM in 2012
Revenue Requirement	Uses forecasted test year
Return on Equity (ROE)	Authorized ROE is 10.15%
Incentive Mechanism for 2010	Earning Sharing Plan: ROE greater than 11.15% but less than 12.15% Con Ed will share 50% of earnings with customers. ROE greater than or equal 12.15% but less than or equal to 13.15% Con Ed will share 75% of earnings with customers and retain 25%. ROE greater than 13.15% Con Ed will share 90% of earnings with customers and retain 10%.
Incentive Mechanism for 2011 and 2012	Earning Sharing Plan: ROE greater than 10.65% but less than 12.15% Con Ed will share 60% of earnings with customers and retain 40%. ROE greater than or equal 12.15% but less than or equal to 13.15% Con Ed will share 75% of earnings with customers and retain 25%. ROE greater than 13.15% Con Ed will share 90% of earnings with customers and retain 10%.
Effective Years	Multi-year rate case is in effect from April 1, 2010 to March 31, 2013 with each year's rate increase effective on April 1.
Regulatory Oversight	Multi-Year rate case does not limit the ability of jurisdictional regulators to call the company in at any time for a full rate review
Benefits of Mutli-Year Rate Plan	Produces a more predictable revenue stream and certainty for Con Ed to make investments necessary to continue the provision of safe and reliable service. Allows the company to direct resources that would otherwise be committed to annual electric rate cases to focus on operating the business. Places strong emphasis on Con Ed's ability to manage costs in an efficient and effective manner. Provides incentives and creative measures that encourage discipline within the corporate structure. Provides rate mitigation measures for customers.

ATTACHMENT A

How Should Regulators View Cost Trackers?

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September 2009

09–13

Acknowledgments

The author wishes to thank Mr. Scott Hempling and Mr. Adam Pollock, both of NRRI; Professor Dr. Douglas N. Jones of The Ohio State University; Mr. Michael McFadden of McFadden Consulting Group; Professor Carl Peterson of the University of Illinois Springfield; and Mr. Joseph W. Rogers of the Massachusetts Attorney General Office for their comments on an earlier draft of this paper. The author is responsible for any remaining errors in the document.

Online Access

The reader can find this paper on the Web at http://www.nrri.org/pubs/gas/NRRI_cost_trackers_sept09-13.pdf.

Executive Summary

A cost tracker allows a utility to recover its actual costs from customers for a specified function on a periodical basis outside of a rate case. This paper discusses the major issues that state public utility commissions face in evaluating the costs and benefits of these devices.

Several state commissions have approved new cost trackers for a wide array of utility functions in both the electric and natural gas sectors. State commissions have traditionally limited the use of cost trackers, partially because of the perception that they create "bad" incentives and shift risks to a utility's customers. The recent approvals depart from past regulatory practices that sanction trackers only under highly restricted conditions.

The author asserts that state commissions have not given adequate attention to the negative features of cost trackers, which are at odds with the public interest. Specifically, cost trackers diminish the positive effects of regulatory lag and retrospective reviews in deterring utility waste and cost inefficiency. Trackers also could reduce regulatory scrutiny in evaluating cost prudence.

This paper contends that regulators should view cost recovery in a rate case as the "default" practice. A rate case assures scrutiny of a utility's costs and provides strong motivation for the utility to control those costs between rate cases. The utility therefore bears burden to show why a cost tracker is in the public interest. The utility should demonstrate that it would suffer severe financial difficulties under "extraordinary circumstances" without the tracker.

This paper also recommends that regulators consider the advantages of replacing cost trackers (excluding fuel and purchased gas cost trackers) with a single rate-of-return tracker in the form of an earnings-sharing mechanism. This alternative can overcome some of the problems with cost trackers, namely perverse or weak incentives for cost control, the mismatching of total costs and revenues, and inadequate regulatory oversight of costs. An earnings-sharing mechanism also achieves the major objective of cost trackers, which is to prevent a utility from suffering serious financial problems between rate cases.

Table of Contents

How Should Regulators View Cost Trackers?

This paper discusses the major issues regulators face in evaluating the costs and benefits of cost trackers.[1] This paper responds to state public utility commissions' recent actions in approving new cost trackers for a wide array of utility functions in both the electric and natural gas sectors. Historically, state commissions have limited the use of cost trackers, partially because of the perception that they create "bad" incentives and shift risks to a utility's customers. The recent approvals differ from past regulatory practices that sanctioned trackers only under highly restricted conditions.

The author contends that state commissions have not given adequate attention to the negative features of cost trackers. By conflicting with certain regulatory objectives, cost trackers thwart the public interest. Cost trackers undercut the positive effects of regulatory lag and retrospective reviews in deterring utility waste and cost inefficiency. They also could lessen regulatory scrutiny in evaluating the prudence of costs.

This paper defines cost trackers and discusses how they benefit utilities. It then provides the rationales for cost trackers and how they relate to regulatory principles for cost recovery. The paper examines two scenarios; in the first, regulators allow comprehensive cost trackers, while in the second they allow none. The paper ends by recommending a regulatory policy and identifying questions regulators should ask when investigating cost trackers.

I. The Definition and Mechanics of a Cost Tracker

A cost tracker allows a utility to recover its actual costs from customers for a specified function on a periodical basis outside of a rate case.[2] A tracker, in other words, involves the recovery of a utility's actual costs in the periods between rate cases. These costs could include

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[1] Regulators sometimes refer to cost trackers as "riders."

[2] A cost tracker can either provide interim rate relief for a utility or be a permanent fixture that adjusts rates between rate cases based on upward and downward movements in those costs specified in a tracker. As an alternative to a cost tracker, a utility can file for emergency rate relief whenever it encounters a serious financial problem. The commission can specify conditions under which a utility can file an emergency or interim rate filing petitioning for immediate rate relief. This paper does not examine the different regulatory approaches to relieving utilities of any temporary or more permanent serious financial problems. Such a study could compare each approach, including cost trackers, based on its effect on different regulatory objectives.

those that deviate from some baseline or are zero-based.[3] Baseline costs, for example, could include bad debt costs[4] reflected in present rates as determined in the last rate case. A cost tracker could allow adjustments in rates when actual bad-debt costs depart from the baseline level. These adjustments would occur periodically as prescribed previously by a commission.

To benefit customers when actual cost falls below the baseline level, a cost tracker must be "symmetrical." The unpredictability of a cost item—which, as this paper discusses later, is one underlying rationale for a cost tracker—means that test-year cost estimates can overstate or understate the actual costs. Virtually all fuel and purchased gas cost trackers are symmetrical, with customers benefiting when commodity-energy costs fall (e.g., since the autumn of 2008).

Cost trackers also could apply to all of the costs associated with a particular business function or task. Under this zero-based approach, for example, the entire cost of a gas utility's new investments in upgrading the safety of its distribution system would be amortized and recovered later from customers in lieu of inclusion in base rates. The same cost recovery procedure can occur for a utility's energy-efficiency initiatives.

Some cost trackers, such as fuel adjustment clauses (FAC) and purchased gas adjustments (PGAs), adjust rates in response to changes in the price of fuels used by generating facilities and purchased gas for gas utilities.[5] Certain cost trackers approved over the last couple of years allow for rate adjustments when the cost for a particular business function, for whatever reason, changes. A tracker for bad debt, for example, does not distinguish between an increase because of a greater number of nonpaying customers or higher debt per customer.

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[3] "Zero-based" refers to *all* the costs associated with a specific function, rather than just increments or decrements from test-year costs.

[4] These costs represent money owed by customers to a utility that the utility has determined to be uncollectible.

[5] NRRI has conducted several studies on FACs and PGAs. *See*, for example, Robert E. Burns, Mark Eifert, Peter Nagler, *Current PGA and FAC Practices: Implications for Ratemaking in Competitive Markets* (Columbus, Ohio: NRRI, November 1991), NRRI 91-13; Robert E. Burns and Mark Eifert, "Designing Fuel and Purchased Gas Adjustment Clauses to Provide for Incentive Compatibility in a More Competitive Environment," *Proceedings of the Eighth NARUC Biennial Regulatory Information Conference* (Columbus, Ohio: NRRI, September 1992); Kevin A. Kelly, Timothy Pryor, Nat Simons, *Electric Fuel Adjustment Clause Design* (Columbus, Ohio: NRRI, 1979), NRRI 79-3; and Douglas N. Jones, Russell J. Profozich, Timothy Biggs, *Electric and Gas Utility Rate and Fuel Adjustment Clause Increases, 1978 and 1979* (Columbus, Ohio: NRRI, 1981), NRRI 81-5.

II. Principles for Cost Recovery

A. "Reasonable opportunity" criterion

State commissions have applied myriad criteria for utility cost recovery. Regulators are legally bound to allow utilities the opportunity to recover prudently incurred costs. Prudent costs reflect utility management that makes rational and well-informed decisions. The word "opportunity" can refer to the utility having a good chance of earning its authorized rate of return and is distinct from an entitlement.[6] "Earning the authorized rate of return" means that the utility recovers its prudent variable costs (e.g., operations and maintenance) and earns a return of and on prudently incurred fixed costs, including its cost of capital as determined in the last rate case.

B. Incentive effects of cost trackers

Commissions traditionally allow cost recovery only after a rate case review. Other alternatives such as a cost tracker would require that a utility show violation of the "opportunity" condition for particular cost items. A violation can occur when a certain cost is substantial, unpredictable, and generally beyond a utility's control. Other than costs relating to fuel and purchased power and gas, few other costs fall within the confines of "special circumstances."[7] Parties to regulatory proceedings naturally disagree over when these circumstances exist. To clarify their positions to utilities, intervening groups, and the general public, commissions should consider issuing policy statements articulating standards for the recovery of costs through trackers.

Regulators, until recently, have taken a cautious approach to trackers, partially because they weaken the incentive of a utility to control its costs.[8] Controlling utility costs is a primary

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[6] One interpretation is that the utility earns its authorized rate of return over a number of years, rather than each year. Regulators, investors, and utilities do not expect uniform rates of return across years. Instead, they ostensibly presume that in some years the rate of return will be below the authorized level, while in other years it would be above the authorized level. Regulators, for example, set rates based on "normal" weather. They expect that summer weather will be hotter than normal in some years and cooler than normal in others. For a typical electric utility, having a hotter-than-normal summer and a cooler-than-normal summer often means the utility earns a high rate of return and a low rate of return for those years respectively. But regulators expect normal weather over a number of years.

[7] An exception also might include the costs associated with a major storm causing extensive damage to a utility's infrastructure.

[8] The cost trackers discussed in this paper assume price adjustments based on changes in the actual cost of the utility. If instead price adjustments relate to cost changes for a peer group or other factors outside the control of the utility, the incentive problems identified in this paper would mostly disappear. Some cost trackers attempt to incorporate benchmarks that reflect performance exogenous to an individual utility. Defining the appropriate benchmark is a crucial but difficult task in designing a performance-based tracker. *See*, for example, Ken Costello and

objective of regulators because it contributes to lower rates and reflects efficient utility management. Cost trackers can, in various ways, result in higher utility costs.[9] First, they undercut the positive effects of regulatory lag on a utility's costs. "Regulatory lag" refers to the time gap between when a utility undergoes a change in cost or sales levels and when the utility can reflect these changes in new rates. Economic theory predicts that the longer the regulatory lag, the more incentive a utility has to control its costs; when a utility incurs costs, the longer it has to wait to recover those costs, the lower its earnings are in the interim. The utility, consequently, would have an incentive to minimize additional costs. Commissions rely on regulatory lag as an important tool for motivating utilities to act efficiently.[10] As economist and regulator Alfred Kahn once remarked:

> Freezing rates for the period of the lag imposes penalties for inefficiency, excessive conservatism, and wrong guesses, and offers rewards for their

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James F. Wilson, *A Hard Look at Incentive Mechanisms for Natural Gas Procurement*, NRRI 06-15, November 2006, at http://www.nrri.org/pubs/gas/06-15.pdf.

[9] Theoretical and empirical studies provide some evidence of the incentive problems associated with one kind of cost trackers, FACs. *See*, for example, David P. Baron and Raymond R. DeBondt, "Fuel Adjustment Mechanisms and Economic Efficiency," *Journal of Industrial Economics*, Vol. 27 (1979): 243-69; David P. Baron and Raymond R. DeBondt, "On the Design of Regulatory Price Adjustment Mechanisms," *Journal of Economic Theory*, Vol. 24 (1981): 70-94; David L. Kaserman and Richard C. Tepel, "The Impact of the Automatic Adjustment Clause on Fuel Purchase and Utilization Practices in the U.S. Electric Utility Industry," *Southern Economics Journal*, Vol. 48 (1982): 687-700; and Frank A. Scott, Jr., "The Effect of a Fuel Adjustment Clause on a Regulated Firm's Selection of Inputs," *The Energy Journal*, Vol. 6 (1985): 117-126. The first two studies applied a general model to show that FACs tend to cause a utility to overuse fuel relative to other inputs, pay more for fuel prices, and choose non-optimal, fuel-intensive generation technologies. The third study provided empirical support for this prediction. The fourth study showed that some types of FACs cause bias in fuel use and that FACs in general weaken the incentive of a utility to search for lower-priced fuel. It provided empirical evidence that electric utilities with an FAC pay higher fuel prices than utilities without an FAC.

[10] Regulatory lag is a less-than-ideal method, however, for rewarding an efficient, and penalizing an inefficient, utility. Some of the additional costs could fall outside the control of a utility (e.g., increase in the price of materials), and any cost declines might not correlate with a more managerially efficient utility (e.g., deflationary conditions in the general economy). As discussed elsewhere in this paper, regulators are more receptive to cost trackers when: (1) regulatory lag can cause a substantial movement in a utility's rate of return between rate cases, and (2) the utility has little control over how much its actual costs will deviate from its test-year costs.

opposites; companies can for a time keep the higher profits they reap from a superior performance and have to suffer the losses from a poor one.[11]

Rational utility management, as a general rule, would exert minimal effort in controlling costs if it has no effect on the utility's profits.[12] This condition occurs when a utility is able to pass through (with little or no regulatory scrutiny) higher costs to customers with minimal consequences for sales. Cost containment constitutes a real cost to management. Without any expected benefits, management would exert minimum effort on cost containment. The difficult problem for the regulator is to detect when management is lax. Regulators should concern themselves with this problem; lax management translates into a higher cost of service and, if undetected, higher rates to the utility's customers. Regulators should closely monitor and scrutinize costs, such as those subject to cost trackers, that utilities have little incentive to control.

When mechanisms for cost recovery differ across functional areas, perverse incentives can arise that would make it profitable for the utility not to pursue cost-minimizing activities.[13] The result is higher rates to utility customers. A utility with a FAC might postpone maintenance of a power plant even when it would cost less than the savings in fuel costs. The utility could not immediately (or even at any time) recover additional maintenance costs, while it could pass the higher fuel costs through the FAC.

Cost trackers, in the long run, can bias a utility's technological and investment decisions. A utility recovering fuel costs through a FAC, for example, might want to adopt fuel-intensive generation technologies even if they are more expensive from a life-cycle perspective.[14] The result, again, is higher rates to utility customers.

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[11] Alfred E. Kahn, *Economics of Regulation, Vol. 2* (New York: John Wiley & Sons, 1971), 48.

[12] I assume here that reducing cost has no effect on the quality or quantity of utility service. Controlling costs, therefore, refers to eliminating or reducing "wasteful" expenses that would result in no decline in the value of utility service. The author imagines a situation in which utilities would attempt to defer maintenance costs until the commission sets new base rates that account for those costs.

[13] In the example above, regulators could eliminate any perverse incentive by simply allowing a cost tracker for maintenance expenses.

[14] *See*, for example, the Baron and DeBondt studies cited in footnote 9.

Cost trackers also could motivate utilities to shift more of their costs to functions subject to trackers.[15] They might, for example, want to classify routine maintenance costs as a capital expense that receives tracker cost recovery. Such shifts could lead to earning an excessive rate of return. Regulators implementing trackers should carefully define applicable costs. They should also examine costs claimed under trackers to ensure that the utility recovers only appropriate costs through the tracker.[16]

An important incentive for cost control by regulated utilities is the threat of cost disallowance from retrospective review.[17] To the extent that cost trackers dilute the frequency and quality of these reviews, further erosion of incentives for cost control occurs. With less regulatory oversight and auditing, which often accompany rate cases, a utility might have less concern over the costs it incurs. Regulators have long recognized the importance of retrospective reviews in motivating a utility to avoid cost disallowances from grossly subpar performance.

If a utility has a number of cost trackers, the regulator might want to consider staggering the timing of retrospective reviews to avoid having inadequate staff resources to review the adjustments for individual cost trackers. Some utilities have comprehensive trackers that recover a wide array of costs (e.g., purchased gas, bad debt, energy-efficiency activities, and environmental activities). For these trackers, it would be especially challenging for a regulator to conduct an adequate retrospective review of each item simultaneously.[18]

A contradiction seemingly exists between the criterion that trackers should apply only to those costs beyond the control of a utility and the assertion that the modified incentives caused by trackers can lead to inflated costs. One response is that a utility has at least some control over most of its costs. Except for certain taxes and some other cost items, the actions of utility

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[15] One example is when a tracker for new capital expenditures creates an incentive for a utility to shift labor costs from maintenance to capital projects. In this instance, the utility can schedule employees to work on the capital projects, and maintenance is delayed. The utility consequently reduces its maintenance costs and thereby keep the savings, and increase its capital expenditures, which it recovers through the tracker. I thank Michael McFadden for this example.

[16] I thank Adam Pollock for this insight.

[17] Many regulatory experts view retrospective reviews as dissuading a utility from poor decisions with the threat of a penalty—for example, making the utility more diligent and careful in its planning and procurement. Given asymmetric information, where a utility knows more about its operations and market supply/demand conditions than the commission, some analysts characterize retrospective views as a second-best mechanism to market-like incentives. For most gas utilities, the strong incentives for controlling purchased gas costs derive mainly from the time lag between the incurrence of a cost and its recovery from retail customers, and regulatory prudence reviews where, for example, abnormal costs attract special attention and a review.

[18] I thank Joseph Rogers for this insight.

management can affect costs. Even for fuel or purchased gas, utility management's actions can affect their total costs. Although for the most part the marketplace determines the price paid for these items, utilities can negotiate prices under long-term contracts and decide on the mix and sources of different fuels and purchased gas.[19]

Commissions also tend to avoid cost recovery that results in radical price volatility to utility customers. Such a policy could preclude monthly price adjustments from changes in fuel costs or purchased gas costs. It also might result in a phase-in of the construction costs of a new base-load-generating facility.

III. Utilities' Perspective on Cost Trackers

Under traditional ratemaking, the utility recovers all costs after a rate case review. It requires no commission activity between rate cases. Traditional ratemaking provides base rates based on the test year. A commission relies heavily on cost-of-service studies to determine base rates. Base rates have two characteristics: (1) a commission sets them in a formal rate case, and (2) they remain fixed until the utility files a new rate case and the commission makes a subsequent decision. The costs represent those calculated for a designated test year and exclude those costs recovered in trackers and other mechanisms. No matter how much the actual utility's costs and revenues deviate from their test-year levels, rates remain fixed until the commission approves new ones in a subsequent rate case. The exception is when a commission allows for interim rate relief under highly abnormal conditions that jeopardize a utility's financial condition.

Utilities have argued that a more dynamic market environment, characterized by the increased unpredictability and volatility of certain costs, justifies the recovery of certain costs through a tracker rather than in base rates.[20] Utilities have also asserted that the static nature of the "test year" sometimes denies them a reasonable opportunity to earn their authorized rate of return. They contend that cost trackers advance the ratemaking goals by matching revenues to actual costs.

In contrast to base rates, cost trackers offer a utility the advantages of: (1) shortening the time lag between the incurrence of a cost and its recovery in rates (i.e., curtailing regulatory lag),

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[19] A utility, for example, might be lax in finding the best deals for gas supplies, in applying more resources by employing more highly qualified staff, or in acquiring superior market intelligence. *See,* for example, Ken Costello, *Gas Supply Planning and Procurement: A Comprehensive Regulatory Approach*, NRRI 08-07, June 2008, at http://nrri.org/pubs/gas/Gas_Supply_Planning_and_Procurement_jun08-07.pdf.

[20] *See*, for example, Russell A. Feingold, "Rethinking Natural Gas Utility Rate Design: A Framework for Change," presented at the American Gas Foundation Executive Forum, held at The Ohio State University, May 23, 2006.

(2) increasing cost-recovery certainty,[21] and (3) lessening the regulatory scrutiny of its costs. Normally, in a rate case a regulator closely reviews the utility's costs before approving them for recovery from customers. Regulators often less rigorously scrutinize a utility's costs when recovered through a tracker.[22] Overall, cost trackers lower a utility's financial risk by stabilizing its earnings and cash flow.

Utilities increasingly have asked their state public utility commissions to depart from traditional regulation by approving new cost-recovery mechanisms for different business activities. Some gas utilities want to expand the scope of their PGA clauses to include a wider array of costs. Current cost trackers in the natural gas sector, other than those for purchased gas costs, apply to functions including pipeline integrity management, pipeline replacement costs (e.g., accelerated cast iron main replacement program), bad debt, energy-efficiency costs, general infrastructure costs, manufactured gas plant remediation, stranded restructuring costs, property taxes, post-retirement employee benefits, and environmental costs.

IV. Regulatory Rationales for Cost Trackers

A. "Extraordinary circumstances"

State commissions have traditionally approved cost trackers only under "extraordinary circumstances." Commissions recognize the special treatment given to costs recovered by a tracker; they consider cost trackers an exception to the general rule for cost recovery. This view places the burden on a utility to demonstrate why certain costs require special treatment.

The "extraordinary circumstances" justifying most of the cost trackers that commissions have historically approved have been for costs that are: (1) largely outside the control of a utility, (2) unpredictable and volatile,[23] and (3) substantial and recurring. Historically, commissions required that all three conditions exist if a utility wanted to have costs recovered through a tracker. Fuel costs were a good candidate because of their influence by factors beyond

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[21] Between rate cases, for example, a utility might incur costs unanticipated by the test-year calculation and thus not recovered from its customers.

[22] The regulator, for example, might have less time to review these costs or just might consider them too unimportant to warrant a separate review. Another explanation might be that rate cases are transparent and well-publicized, putting pressure on regulators to closely review all aspects of a rate case filing. These reasons are just the author's speculations. A pertinent research question is whether this hypothesis has validity.

[23] Even if the forecast of a cost item is highly accurate in the long run, it can fluctuate widely in the short run, causing possible serious cash-flow problems for the utility. The utility might then have to purchase short-term debt and other financing. The author thanks Carl Peterson for this insight.

the control of a utility, their volatility, and their large size. Commissions recently have approved cost trackers when not meeting all three conditions, especially the third (substantial and recurring costs).[24]

The last "extraordinary circumstance," substantial and recurring costs, greatly restricts the costs eligible for cost tracker recovery. Differences between their test year and actual cost can have a material effect on a utility's rate of return. Legal precedent dictates that regulators must set reasonable rates that allow a prudent utility to operate successfully, maintain its financial integrity, attract capital, and compensate its investors commensurate with the risks involved.[25] A utility should recover revenues in excess of its operating expenses to provide a "fair return" to investors. Businesses including utilities need to earn a profit to compensate investors for business, financial, and other risks.[26]

Some state commissions have softened or ignored the "substantial and recurring" component of the "extraordinary circumstances" standard. Bad debt, the subject of recent cost trackers, features financial effects that are typically not substantial. Utilities have contended that the unpredictability of this cost makes it difficult to incorporate it accurately into the base rate. Yet, even if this assertion is true, it is questionable whether any bad-debt cost unaccounted for in the test year would inflict substantial financial harm on a typical utility.[27]

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[24] Commissions' rulings seem to reflect the view that regulators have much discretion in approving cost trackers as long as these actions reflect reasonable ratemaking given the facts and circumstances.

[25] The U.S. Supreme Court outlined these conditions in its 1944 order for *FPC v. Hope Natural Gas Co.*, 320 U.S. 591, 605 (1944).

[26] The return on equity for a utility corresponds to the term "normal profits." Both terms involve the cost a utility incurs to attract funds from investors.[26] Let us assume that utility performance should replicate the performance of competitive firms where firms receive normal profits in the long run. A utility would, therefore, earn a return that is reasonable but not excessive. A reasonable return should allow the utility to maintain its credit quality and attract needed capital on reasonable terms, but do no more. Commissions usually consider a rate of return within a "zone of reasonableness" as sufficient but not excessive. They do not guarantee that the utility will earn within this zone; they merely give the utility the opportunity if it performs efficiently and economically.

[27] The outcome would vary across utilities and by period. Especially in bad economic times in conjunction with high energy prices, bad debt can quickly soar, making test-year estimates grossly inaccurate. "Substantial financial harm" has no definitive meaning. It can refer to a situation where a utility has difficulties in raising funds for new investments or faces severe cash flow problems. Such situations can harm customers in the long run, for example, by reducing service reliability and diminishing the utility's credit quality, which in turn can lead to the utility having a higher cost of capital. A tracker for bad debt can also affect how the utility responds to customers who are behind in their payments. It can, for example, make the utility

B. "Severe financial consequences"

Historically, commissions have approved cost trackers to avoid the possibility of a utility suffering a serious financial problem because of cost increases unforeseen at the time of the last rate case.[28] Justification for cost trackers is, therefore, greater when a commission relies on a historical test year that does not recognize the volatility of certain costs or their upward trend over time. Let us assume that a certain operating cost has trended upward (e.g., 2 percent per year) over the past several years. Let us also assume that the commission allows only a historical test year. In this example the utility is likely to under-recover this particular cost. What effect this outcome would have on the utility's overall rate of return depends on the magnitude of any cost increase relative to the utility's earnings and whether other costs fell while rates were in effect.

Commissions do not expect utilities to earn the authorized rate of return during each future period over which new prices are in effect.[29] Commissions implicitly impute a risk premium in the authorized rate of return, partially to account for the earnings volatility from fluctuations in costs or revenues from the test year. Trackers affect what is called "business risk." Business risk refers to the uncertainty linked to the operating cash flows of a business. Business risk is multi-dimensional, inclusive of sales, cost, and operating risks. In the Capital Asset Pricing Model (CAPM), for example, the lower the utility's expected earnings volatility, the lower the measure of the utility's risk relative to the market portfolio (i.e., "beta"). Because

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more lax in its credit policies, which could result in fewer service disconnections, especially for low-income households. In the absence of a tracker, the utility presumably would intensify its efforts to collect money owed by delinquent customers. I thank Michael McFadden for this insight.

[28] *See,* for example, Paul L. Joskow, "Inflation and Environmental Concern: Structural Changes in the Process of Public Utility Regulation," *Journal of Law and Economics*, Vol. 17 (1974): 291-327. A premise behind the wide acceptance of fuel adjustment clauses was that because electric utilities were not responsible for the escalation of fuel costs, commissions should not hold them accountable. Virtually all electric utilities in the 1970s experienced an unprecedented rise in fuel costs, for example, inferring an exogenous event beyond the control of any single utility. Prior to this time, even though FACs were common but fuel prices were much more stable, commissions generally associated changes in the utility's rate of return between rate cases with utility-management performance. A lower rate of return reflected poor performance and a higher rate of return superior performance. (A 1974 study found that 42 out of 51 jurisdictions had some form of fuel adjustment clause. *See* National Economic Research Associates, "The Fuel Adjustment Clause: A Survey of Criticism, Justifications, and Its Applications in the Various Jurisdictions," 1974.)

[29] This statement supports the contention that commissions do not intend the prices they set in a rate case to reflect the utility's actual cost of service for each future year. Commissions, however, judge that the prices they set will allow the utility an opportunity (i.e., a reasonable chance) to earn its authorized rate of return or some return close to the authorized level.

trackers reduce a utility's business risk, a regulator might want to consider revising downward the risk premium of a utility with additional cost trackers or a revenue-decoupling tracker, resulting in a lower return on equity.

If a commission wants to guarantee that the utility will recover its authorized earnings, it would favor a rate design that allows the utility to recover all of its fixed costs in a monthly service charge or a customer charge.[30] Since generally commissions do not, they implicitly recognize the positive incentive effect from allowing a utility's actual rate of return to deviate from the authorized level. Commissions also know that if a utility is continuously earning below its authorized rate of return, the utility has the right to file a general rate increase.

The previous discussion explains why most regulators have favored adjusting rates between rate cases only when such adjustments avoid serious financial situations for utilities. If a commission wanted to assure the utility that it will always earn its authorized rate of return, it would allow the utility to recover all of its actual costs through trackers.[31] Commissions generally do not allow the tracking of all costs because of incentive and other problems, which this paper discusses in Section II.B.

C. An illustration: FACs and PGAs

The wide popularity of FACs and PGAs among utilities and most commissions reflects the perception that these mechanisms are necessary to prevent a utility from earning a rate of return substantially below what was authorized. This perception stems from the magnitude of fuel and purchased gas costs relative to a utility's earnings. Other categories of costs, such as bad debt, are much smaller in size and therefore have smaller earnings consequences.

Until fuel costs started to fluctuate sharply in the 1970s, some energy utilities had to operate without the ability to adjust prices outside a rate case.[32] These utilities shouldered the risks of events between rate cases, but they also retained any high returns from favorable happenings. Prior to around 1970, for example, many electric utilities earned rates of return that were much higher than the authorized levels because of technological improvements, high sales growth, and economies of scale, in addition to the acquiescence of commissions.[33]

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[30] Such a rate design would not guarantee the utility earning its authorized rate of return, as unexpected variable costs would cause the utility's earnings to decline.

[31] This recovery would include fixed costs the commission found prudent in the last rate case. Guarantee of full recovery of all costs would also require a revenue tracker such as revenue decoupling, assuming that the utility recovers some of its fixed costs in the volumetric or commodity charge.

[32] The genesis for these dramatic fuel-cost increases was the Oil Embargo by OPEC and the other Persian Gulf troubles of the 1970s.

[33] Although most state commissions had authority to initiate proceedings to reduce rates, few chose to exercise it.

Not surprisingly, virtually all state commissions believed that trackers for large items such as fuel costs and purchased gas costs were necessary to prevent inordinate rate-of-return fluctuations. Implicit in this belief is the view that the burden on utility shareholders would otherwise be onerous. This factor overwhelmed the arguments against trackers. The major objective of FACs and PGAs, implanted during that era, was to shield the utility's earnings from commodity price volatility. Both debt and equity investors favor these mechanisms in reducing the riskiness of a utility's earnings and cash flow.

V. Two Extreme States of the World: Several and No Cost Trackers

A. A hodgepodge of cost trackers, or a single rate-of-return tracker

If a commission wants a utility always to earn close to its authorized rate of return, it would favor rate adjustments between rate cases for both: (1) actual costs deviating from test-year costs, and (2) actual revenues deviating from test-year revenues. This outcome would require cost trackers covering all of the utility's costs in addition to a revenue decoupling mechanism. (The revenue decoupling mechanism would allow the utility to recover all fixed costs that the commission approved for recovery in the last rate case.)

Putting the utility's future on "autopilot" seems like a reasonable course of action if financial stability is the prime regulatory objective. Considering incentive problems and excessive risk-shifting to customers, this option comes across as much less appealing.

An earnings-sharing mechanism (ESM), which consolidates different cost and revenue trackers, is one ratemaking procedure for stabilizing a utility's rate of return between rate cases. Under this mechanism, the utility adjusts its rates periodically (e.g., annually) when its actual return on equity falls outside some specified band. As an illustration, if the band encompasses a 10 to 14 percent rate of return on equity (with 12 percent as the utility's authorized rate of return established in the last rate case) when the actual return is 9 percent, the utility could adjust its rates upward to increase its return to, or bring it closer to, 10 percent.[34]

An ESM helps to stabilize a utility's rate of return without a full-scale rate case review. Earnings sharing should reduce the frequency of future rate cases and allow adjusted rates to reflect recent market developments, including those affecting a utility's costs.[35] Compared to

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[34] The band implicitly reflects the range for the return on equity that the regulator deems both adequate to keep the utility from financial jeopardy and not so excessive as to be exorbitant. The interpretation of these financial conditions is subjective and open to debate.

[35] Under traditional ratemaking, reducing the frequency of rate cases might allow the utility to over-earn by a substantial amount because of the multi-year accumulation of higher-than-expected sales or lower-than-expected costs, or both. Commissions probably are not so concerned when the utility over-earns for a one- or two-year period, but would be when it over-earns by a "significant" amount over several consecutive years. This reaction would be more

traditional ratemaking, where rates remain fixed between rate cases, ESM weakens regulatory lag and thereby reduces the incentive of a utility to control its costs between rate cases.[36] A commission can lessen this problem by requiring the utility to demonstrate its prudence and offer reasons why specific cost items were higher than their test-year levels.[37]

In sum, an ESM would trigger a price adjustment between rate cases only when the aggregation of revenue and cost departures from test-year levels cause the utility's rate of return to fall outside a specified "band" region. An ESM takes into account the overall profitability of a utility. It assumes the role of a rate-of-return tracker that, in effect, amalgamates different cost trackers into a single cost-recovery mechanism.

The ESM differs from conventional trackers, which account for specific costs or functions in isolation from the utility's overall financial position. Trackers' focus on an individual cost categories can cause utilities to delay coming in for rate cases, with the utility earning an "excessively" high rate of return in the interim. Let us assume that the commission has approved a tracker for new infrastructure expenditures. The new infrastructure expects to lower the utility's maintenance and other operating costs. If the last rate case did not recognize these lower operating costs, the utility's rate of return would be higher, yet because of the tracker, the utility suffers no interim financial losses from incurring infrastructure expenditures.

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acute if the commission believes that fortuitous cirscumstances, rather than superior utility management, caused the high earnings.

[36] This incentive problem exists only when the utility is outside the "band" region and the mechanism requires sharing of "excessive "or "deficient" earnings with customers. This fact suggests a wide "band," as the utility operating within the "band" would have "high-powered" incentives to manage costs because it retains all the economic gains.

[37] The incentive problem would be less pronounced compared to a conventional cost tracker. As long as the utility's rate of return is within the "band" region, it has a similar incentive for cost control as it would between rate cases with fixed prices. (The word "similar" is used because if the "band region" is wide enough, it could defer the next rate case to either increase or decrease rates. This deferral would further strengthen the incentive of the utility to control costs.) Outside the "band" region, the utility's incentive depends upon whether ESM requires the sharing of high or low rates of return between the utility and its customers. Assume, for example, that the "band" region is a 10 to 14 percent rate of return on equity. During the year, the utility earns 15 percent; if the utility has to split the difference between the higher boundary of the "band" region and the actual rate of return by adjusting its prices down, in the example the utility would realize a 14.5 percent rate of return. We assume that the mechanism is symmetrical, so if the utility earns below the lower boundary of the "band" region, say, a 9 percent rate of return, it can adjust prices up to realize a rate of return closer to the lower boundary. This sharing arrangement means that if the utility allows its costs to rise, it either suffers the full consequence (when it operates within the 'band" region) or the partial consequence (when it operates outside). The latter condition creates an incentive problem relative to traditional ratemaking with regulatory lag and fixed prices between rate cases.

On net, the utility benefits and its customers immediately pay for the infrastructure costs without benefiting from the lower operating costs (at least until new rates reflect the lower costs). Such an outcome would violate any common meaning of "fairness" and seriously calls into question the merits of using a single-function tracker without readjusting rates for the effect on a utility's other functional areas.[38] This dynamic suggests that commissions implementing trackers should require their utilities to file rate cases on predetermined intervals.

B. No cost trackers

Under the traditional approach to ratemaking, a utility cannot adjust its rates outside a rate case. No matter what happens to a utility's costs or revenues between rate cases, rates remain fixed. Let us assume that a utility's costs and revenues are volatile and difficult to predict. The utility's rate of return can then deviate substantially (on the upside or downside) from the authorized level.

It is one thing to prohibit trackers for costs that are substantial, volatile and unpredictable, and generally beyond the control of a utility; it is another to reject trackers for costs that lack one or more of these features. *Good regulatory policy rejects cost trackers that are not essential for protecting a utility from a dire financial situation*. The utility, in justifying a cost tracker, should present the regulator with credible information showing that a nontrivial probability exists that the cost item under review will rise sufficiently above the test-year level to place the utility in financial jeopardy.[39] This showing is more likely when the regulator uses a historical test year and the cost item recently has exhibited an upward trend or substantial volatility.[40]

Another conceivable justification for a cost tracker is that it transmits better price signals to a utility's customers. Prices would correspond closer to a utility's actual costs and thus improve economic efficiency. For economic efficiency, customers should see costs reflected in their rates, such that they consume less when costs are higher. The validity of this argument for

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[38] Such a non-uniform treatment of costs could also cause perverse incentives. A utility, for example, might overspend on infrastructure structures to receive the gains from lower operating or other costs that the utility retains for itself until the next rate case.

[39] The term "financial jeopardy" has different interpretations. This state, no matter how it is defined, has the potential to harm customers as well as the utility shareholders. It could cause the deferment of needed capital investments to maintain reliable service, lowering of the utility's credit rating, and an increase in the utility's cost of capital. The time period over which these effects would cause injury to utility shareholders generally would be more immediate than the injury to customers.

[40] A future test year might not improve matters much if the cost item is inherently difficult to predict with any forecast and therefore susceptible to large error.

a cost tracker also depends upon the magnitude and nature of the costs involved.[41] This outcome assumes that a tracker involves a variable cost such as fuel or purchased gas costs. When a tracker relates to a fixed cost (e.g., infrastructure costs), the argument turns more to the "fairness" of a cost-recovery mechanism to the utility. Is a tracker justified because test-year cost calculations expose the utility to potentially high financial risk from unanticipated costs that fall primarily outside the control of a utility?

VI. Putting It All Together

Cost trackers have both positive and negative features that regulators must evaluate.[42] In reaching a decision, the regulator needs to weigh these features to determine what is in the public interest based on how they shift risks, ensure cost recovery, and affect incentives. The main challenge for regulators is to evaluate whether the positives outweigh the negatives to justify a cost tracker.[43]

A. The positive side of cost trackers

The primary benefit of cost trackers, as discussed earlier in this paper, is that they reduce the likelihood that a utility will encounter serious financial problems. If test-year costs fail to reflect accurate projections of a utility's actual cost for future periods, then the utility's earnings can deviate substantially from what a commission approved in the last rate case. Some cost items are difficult to project, as they exhibit high volatility and depend on different variables that by themselves are uncertain.

By reducing regulatory lag and the likelihood of prudence reviews, cost trackers can lower a utility's risk and thus increase its access to capital. The utility could then have a higher credit rating that, in turn, could lower the cost of financing capital projects.[44]

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[41] Distortive price signals can relate to the difference between the utility's short-run marginal cost and the marginal price charge to customers in consuming more electricity or natural gas.

[42] For a thorough and excellent discussion of the advantages and disadvantages of cost trackers, with a focus on fuel adjustment clauses, *see* Michael Schmidt, *Automatic Adjustment Clauses: Theory and Applications* (East Lansing, MI: Michigan State University Press, 1981).

[43] For an analysis of similar issues faced by regulators in evaluating different ratemaking mechanisms in general, *see* Ken Costello, *Decision-Making Strategies for Assessing Ratemaking Methods: The Case of Natural Gas*, NRRI 07-10, September 2007, at http://nrri.org/pubs/gas/07-01.pdf.

[44] This argument is similar to the one used to support including construction work in progress (CWIP) in rate base for electricity transmission.

Cost trackers also coincide with the regulatory objective of setting prices based on the actual cost of service. This condition transmits the right price signal to customers deciding how much of the utility's services to consume.[45]

The development of infrastructure such as the smart grid or other new technology costs might warrant that commissions consider cost-recovery mechanisms such as a cost tracker to guarantee minimum cash flow for a utility. Investors might otherwise perceive excessive regulatory risks that preclude committing funding to a utility.[46] A cost tracker in this instance also might cut down on the frequency of future rate cases. Regulators in the future might want to explore less traditional ways for utilities to recover their costs for new technologies with inherently high operational and financial uncertainties.

As a final benefit, cost trackers can reduce regulatory and utility costs by reducing the number of future rate cases. Rate cases absorb substantial staff resources and time, diverting those scarce resources from other commission activities. Yet it is doubtful that many of the recently proposed trackers involving non-major cost items would have any effect on the timing of future rate cases. Another comment is that the costs associated with serious and continuing audits and the monitoring of costs recovered through a tracker could require substantial resources, either in the form of commission staff or outside consultants.

B. The negative side of cost trackers: the case for traditional ratemaking as a default policy or earnings sharing as a preferred alternative

Cost trackers can reduce utility efficiency, as described above. "Just and reasonable" rates require that customers do not pay for costs the utility could have avoided with efficient or prudent management. Regulation attempts to protect customers from excessive utility costs by scrutinizing a utility's costs in a rate case, conducting a retrospective review of costs, applying performance-based incentives, and instituting regulatory lag. Cost trackers diminish one or more of these regulatory activities. In some instances, they diminish all of them. The consequence is the increased likelihood that customers will pay for excessive utility costs.

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[45] One issue that has emerged in states where trackers have become a major method for cost recovery relates to the allocation of those costs across customer classes. Cost allocation determines the actual prices that different customers pay for utility service.

[46] One alternative to reducing regulatory risk through trackers would be for a commission to articulate in a policy statement or other document that it would not apply 20-20 hindsight to determine the cost recovery of new investments. A commission can express, for example, that it will not subject specific utility decisions to prudence reviews. One method of doing so is providing pre-approval for projects before they enter service. For a more detailed discussion of pre-approval mechanisms, *see* Scott Hempling and Scott Strauss, *Pre-Approval Commitments: When And Under What Conditions Should Regulators Commit Ratepayer Dollars to Utility-Proposed Capital Projects?* NRRI 08-12, November 2008, at http://nrri.org/pubs/electricity/nrri_preapproval_commitments_08-12.pdf.

This paper recommends that regulators approve cost trackers only in special situations where the utility would have to show that alternate cost-recovery mechanisms could cause extreme financial problems. This showing requires utilities to provide a distribution of possible cost futures and an assessment of their likelihood. If a certain cost item has high volatility and unpredictability, represents a large component of the utility's revenue requirement and is recurring, and is generally beyond a utility's costs, it becomes a candidate for "tracker" recovery.

Even then, the regulator should consider the adverse incentive effects and how he or she can compensate for this problem.[47] Regulators should condition any approval of a cost tracker on the utility's filing information on its performance for those functional areas directly or indirectly affected by the tracker. For example, has the FAC caused a utility to spend less money on plant maintenance costs, jeopardizing reliability and inflating total utility costs because of higher avoidable fuel costs? These conditions can harm the utility's customers in the long run.

No other rationale merits departing from cost recovery through rate cases. This limited application of cost trackers provides the benefits of:

1. using the same cost-recovery mechanisms for all utility functions to prevent perverse incentives (perverse incentives can lead to a higher cost of service and utility rates);

2. balancing a utility's total costs and total revenues (without this balancing, it is conceivable that the utility could recover one cost item through a tracker and over-recover other costs set in the last rate case to result in the utility earning above its authorized rate of return); a rate case has the attractive feature of matching revenue with costs on an aggregate basis;

3. retaining sufficient regulatory lag to provide the utility with more motivation to control costs (regulatory lag is an important feature of traditional ratemaking in forcing the utility to shoulder the risk of higher costs between rate cases); and

4. scrutinizing a utility's costs and performance in different areas of operation (commissions review costs more rigorously in a rate case setting, decreasing the likelihood that customers will recover a utility's imprudent costs).[48]

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[47] The commission can monitor the utility's performance or include a performance-based incentive component in the tracker mechanism. *See* the NRRI study cited in footnote 8 for a description and analysis of incentive-based gas procurement mechanisms.

[48] In theory, a commission can expend the same resources and effort toward inspecting a utility's costs recovered through a tracker as it does for costs determined in a rate case. In practice, however, the author shares the widely held view that commissions and non-utility parties devote fewer resources to this task for costs recovered through a tracker. Confirmation of this view would require a systematic study that would compare, among other things, the resources expended by the commission and non-utility stakeholders per dollar recovered under trackers and in a rate case.

The earlier discussion points to the advantages of replacing cost trackers (excluding fuel and purchased gas cost trackers) with a single rate-of-return tracker in the form of an earnings-sharing mechanism. This alternative overcomes some of the problems with cost trackers, namely perverse incentives and weak incentives for cost control, the mismatching of a utility's *total* costs and revenues, and inadequate regulatory oversight of costs.[49] An earnings-sharing mechanism is also able to achieve the major objective of cost trackers, namely preventing utilities from suffering serious financial problems between rate cases.

A single rate-of-return tracker can also address the "fairness" issue of why a utility should not recover from customers a cost increase (e.g., property taxes) between rate cases that is completely beyond its control. This mechanism would, in effect, allow the utility to recover the increased costs, but only if it was already earning a "low" rate of return (i.e., a return below the "band" region discussed above). One major problem with cost trackers is that they allow a utility to increase its prices even if the utility is already earning a higher-than-authorized rate of return (or beyond the "zone of reasonableness" set in the last rate case). A commission would not allow this outcome under traditional regulation.

VII. Questions Regulators Should Ask

This paper discusses the major issues regulators face in evaluating cost trackers. Well-informed decisions require regulators to ask certain questions, for which this paper provides some introductory responses. The following is a list of the most pertinent questions:

1. Does a cost-tracker proposal meet the regulatory test of acceptability? What minimum threshold should a regulator set for consideration of a cost tracker?

2. What special circumstances exist to warrant cost recovery outside of a rate case?

3. What evidence does a utility present showing that the absence of a tracker for a particular cost could place it in financial jeopardy?

4. In addition to cost trackers, what other cost-recovery mechanisms can regulators rely on to allow a utility to recover substantial unexpected costs between rate cases? What are the public-interest effects of these mechanisms relative to cost trackers?

5. What advantages does a cost tracker offer? What are its disadvantages?

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[49] Regulators can overcome some of these problems. They can, for example, require that a utility with cost trackers file a rate case no less often than every three years or however often frequency regulators consider appropriate. Regulators can also require prudence reviews of utility activities associated with trackers on a regular basis. I thank Michael McFadden for these insights.

6. How should regulators weigh the downsides of cost trackers relative to the upsides? How important are adverse incentive effects relative to the value of stabilizing a utility's rate of return?

7. How should a regulator account for the net-cost effects of a new investment (e.g., capital costs less savings in operating costs) for which the utility wants cost recovery through a tracker?

8. How would the accumulation of cost trackers for a utility motivate the utility to take risks and improve its overall cost performance?

9. If a cost tracker is justified, how can regulators structure it to mitigate potential problems such as weakened incentives for cost control?

10. What conditions should a regulator attach to the approval of a cost tracker?

    a. Should it require the utility to report on its cost performance in functional areas directly and indirectly affected by the tracker?

    b. Should the regulator also require that all costs recovered through trackers be subject to a thorough prudence review?

    c. Should the regulator reduce the utility's return on equity to account for the lower risk resulting from the tracker?