January 11, 2023 **PUBLIC DOCUMENT**

Will Seuffert
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, Minnesota 55101-2147

RE: **PUBLIC Response Comments of the Minnesota Department of Commerce, Division of Energy Resources**
Docket No. E015/M-22-547

Dear Mr. Seuffert:

Attached are the **PUBLIC** response comments of the Minnesota Department of Commerce, Division of Energy Resources (Department) in the following matter:

Minnesota Power's Petition for Approval to Recover Reagent Costs through the Fuel and Purchased Energy Rider

The Company filed the initial Petition on October 20, 2022. The Department filed its Comments on November 10, 2022 and Minnesota Power filed reply comments on December 15, 2022, submitted by:

Hillary A. Creurer
Regulatory Compliance Administrator
Minnesota Power
30 West Superior Street
Duluth, MN 55802-2093

The Department recommends the Minnesota Public Utilities Commission (Commission) **deny** the petition.

The Department is available to answer any questions the Commission may have.

Sincerely,

/s/ ANDREW GOLDEN
Financial Analyst

/s/ HOLLY SODERBECK
Financial Analyst

AG, HS/ja
Attachment

COMMERCE DEPARTMENT

Before the Minnesota Public Utilities Commission

PUBLIC Response Comments of the Minnesota Department of Commerce Division of Energy Resources

Docket No. E015/M-22-547

I. INTRODUCTION

In its Petition, Minnesota Power (Minnesota Power or the Company) requested the Minnesota Public Utilities Commission (Commission) allow the Company to recover reagent costs[1] through the Fuel and Purchased Energy Rider (FPE Rider).

Minnesota Power proposed to allocate reagent costs similar to Midcontinent Independent System Operating (MISO) costs in the FPE Rider.

On November 10, 2022, the Minnesota Department of Commerce, Division of Energy Resources (Department) submitted Comments regarding the Company's Petition. The Department requested additional information before providing its recommendation to the Minnesota Public Utilities (Commission).

On December 15, 2022, the Company submitted its Reply to the Department's request for additional information.

The Department reviewed the additional information the Company submitted and provides recommendations to the Commission.

II. DEPARTMENT ANALYSIS OF COMPANY'S REPLY COMMENTS

In its Reply Comments, the Company provided the additional information the Department requested as detailed below.

A. REAGENT COSTS

The Department requested the Company provide the amount of reagent costs the Company expects to be included in base rates in the Company's ongoing general rate case (Docket No. E015/GR-21-335). The Department also requested an explanation if any intervening parties opposed the proposed test year amounts.

[1] The Company uses reagents to reduce pollutants from its power plants to comply with federal and state air quality regulations.

The Company's proposed 2022 test year amount for reagent costs is $2.6 million (total Company). The Company did not receive any recommended adjustment from intervening parties.[2]

The Company also provided the following reagent costs for 2022 as shown in the following table:

Table 1: Reagent Costs[3]
2022 Actuals January through October, Forecasts November and December

Month	Boswell Unit 3	Boswell Unit 4[4]	Total
January 2022 Actuals	$ 126,199	$ 172,405	$ 298,604
February 2022 Actuals	$ 143,637	$ 342,503	$ 486,140
March 2022 Actuals	$ 233,723	$ 382,102	$ 615,825
April 2022 Actuals	$ 150,544	$ 66,298	$ 216,842
May 2022 Actuals	$ 177,519	$ 6,506	$ 184,025
June 2022 Actuals	$ 240,733	$ -	$ 240,733
July 2022 Actuals	$ 179,079	$ 272,503	$ 451,582
August 2022 Actuals	$ 229,335	$ 295,206	$ 524,541
September 2022 Actuals	$ 32,784	$ 303,942	$ 336,726
October 2022 Actuals	$ 160,833	$ 350,736	$ 511,569
November 2022 Forecasted	$ 57,424	$ 140,110	$ 197,534
December 2022 Forecasted	$ 89,375	$ 165,448	$ 254,823
Total 2022 Costs	**$ 1,821,185**	**$ 2,497,759**	**$ 4,318,944**

Minnesota Power stated it, "is not seeking to recover reagent costs for 2022 through the FPE Rider and is not asking for the known under-collection balances to be recovered."[5] Minnesota Power proposed to incorporate reagent costs incurred on or after January 1, 2023 into the Fuel and Purchased Energy Rider (FPE Rider) and to remove the costs from base rates. Minnesota Power proposed to reflect any rate design impacts with the implementation of final rates.[6]

The Department again notes the Company over-collected reagent costs by approximately $19.7 million in 2016 through 2021, as provided in the following table. The table takes each year's actual reagent costs, by unit, less $1,480,607 for Boswell Unit 3 included in base rates since the 2016 rate case and $5,044,161 for Boswell Unit 4 included in base rates.

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[2] Company Reply Comments, p. 2.
[3] Company Reply Comments, p. 2.
[4] Minnesota Power costs only, does not include WPPI costs.
[5] Company Reply Comments, p. 3.
[6] Company Reply Comments, p. 3.

Table 2: Over-collection of Reagent Costs, 2016 through 2021[7]

Year	Boswell Unit 3	Boswell Unit 4*	Total
2016	301,029	2,478,091	2,779,120
2017	464,562	2,839,999	3,304,561
2018	336,168	2,609,602	2,945,770
2019	692,662	2,962,916	3,655,578
2020	605,801	3,142,220	3,748,021
2021	122,289	3,126,166	3,248,455
Total	**2,522,511**	**17,158,994**	**19,681,505**

Given their historic over-recovery, the Department is not convinced by the Company's argument.

B. REAGENT PRICES

The Department requested Minnesota Power provide additional information regarding reagent costs and prices.

The Company stated its accounting system does not track reagent costs by product name, shipping costs, fuel surcharge, etc. and it would be administratively burdensome to analyze each individual invoice to obtain the requested data. The Company also stated it does not evaluate individual price components when forecasting reagent costs.[8]

i. Ammonia

Specifically, the Department requested the Company provide the price paid for ammonia, broken out by fuel surcharge, commodity price, etc. The Company provided ammonia pricing ($/lb) from 2016 through November 2022 in its Reply Comments.[9] The Company also provided reagent agreement and monthly pricing sheets in Attachments 1 and 2 to its Reply Comments.

In addition, the Department notes on the Company's Attachment 1, page 18, Minnesota Power could qualify for rebates for its purchases. **The Department requests the Company provide the dollar amount in rebates the Company received since 2016 and if the Company included the rebate amounts as an offset to its costs.**

[7] Department Comments (11/10/2022), p. 6.
[8] Company Reply Comments, p. 4.
[9] Company Reply Comments, p. 3.

ii. Lime

The Department requested the Company provide the Company's anticipated contract or purchase agreement for lime after February 23, 2023, which is when the Company's existing contract expires. The Company provided the 2023 budget for lime is based on the contracted price from 2022 plus a recommendation from the Company's vendor due to current impacts on commodity prices and logistics within the supply chain.[10]

The Company is currently in the contract negotiation process with its lime vendor.[11]

C. REAGENT USE

The Department requested the Company provide the annual net generation (net MWh) for Boswell Energy Center Units 3 and 4 (BEC3 and BEC4, respectively) from 2016 to 2021 actuals and from 2022 to 2026 forecasts.

The following table provides each unit's net generation compared to budgeted amounts.

[10] Company Reply Comments, p. 3.
[11] Company Reply Comments, p. 4.

Table 3: Annual Net Generation BEC3 and BEC4[12]

	BEC3		BEC4[13]		Total		Total
	Budgeted MWhs	Actual MWhs	Budgeted MWhs	Actual MWhs	Budgeted MWhs	Actual MWhs	Actual - Budgeted MWhs
2016 Actuals	[TRADE SECRET DATA HAS BEEN EXCISED]						
2017 Actuals							
2018 Actuals							
2019 Actuals							
2020 Actuals							
2021 Actuals							
2022 Test Year							
2022 Actual - October 2023							
2022 Forecast							
2023 Forecast							
2024 Forecast							
2025 Forecast							
2026 Forecast							

D. REAGENT COST RECOVERY METHOD

The Department requested the Company provide the reasoning and support for requesting to change recovery of reagent costs through the instant petition, as opposed to a general rate case proceeding.

In its Reply Comments, the Company stated it requested to change recovery method due to recent changed circumstances including:

- The continuing shift in the Company's generation mix and increase in economic dispatch, leading to greater generation variability at Boswell.
- Higher energy market prices driving greater than anticipated dispatch at Boswell, resulting in greater variable use.

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[12] Company Reply Comments, p. 4
[13] Minnesota Power only.

- The Commission's Order granting Otter Tail Power Company's request to recover reagent costs through is fuel clause in its recent rate case.[14]

The Company also stated the underlying reason provided in Otter Tail Power's rate case for allowing reagent cost recovery through a rider equally apply to Minnesota Power because both utilities' generation dispatch is based on market demand and economics outside the utilities' control.[15]

The Department is not persuaded by the Company's arguments in its Reply Comments. The Department continues to disagree with the use of tracking mechanisms or rider mechanisms except in very limited circumstances.

To expand on the reasons the Department disagrees with the Company's proposal:

- The Company's actual reagent costs were significantly below the reagent costs included in base rates from 2016 to 2022, in the amount of approximately $19.7 million. The Company, therefore, over-recovered reagent costs in its base rates, every year, from 2016 to 2021 for a $19.7 million total over-recovery.

- The Company stated, "Minnesota Power has consistently taken the position that reagent costs should be recovered through the FPE Rider."[16] However, the Company did not make this request in the Company's ongoing rate case in Docket No. E015/GR-21-335. It is the Department's position that a rate case is a more appropriate venue for the complete analysis needed for this type of request. Rate cases involve a holistic view of the Company's financials, as opposed to one expense item.

- The Department is concerned that allowing the Company to recover all reagent costs through the FPE Rider without a careful review of costs would not be reasonable and would likely reduce the Company's efforts for efficiency and cost minimization. When costs are established in base rates, the Company has an incentive to keep these costs as low as possible because the Company and its shareholders bear any difference between the amount included in base rates and actual expenses going forward.

- Allowing true-up mechanisms or trackers can allow a utility to increase its prices even if the utility is already earning a higher-than-authorized rate of return set in its last rate case.[17]

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[14] Company's Reply, p. 5.
[15] Company's Reply, p. 5.
[16] Company's Reply, p. 5.
[17] Department Attachment 1, *How Should Regulators View Cost Trackers?* Ken Costello (2009), The Electricity Journal.

- The amount of time required to track and manage each special recovery mechanism is substantial.

- The Company noted the FAC mechanism reform (FAC reform) now provides the ability to track and report annually the volumes and costs associated with reagents. However, the Department is still concerned, even with the reform, that the automatic fuel adjustment filings do not allow for a holistic review of the Company's financials. In addition, the reform occurred in December 2017,[18] prior to the Company's initial filings in its ongoing rate case in Docket No. E015-GR-21-335.[19] The more appropriate avenue for this request is a general rate case proceeding, allowing for extensive review and participation from interested parties to brief the issue and participate in deliberation.

- The Company noted the Commission's recent approval for Otter Tail Power to recover reagents through their automatic fuel adjustment filings. However, as stated in Otter Tail Power's rate case, it is the Department's position that moving reagent costs to the FPE Rider would likely reduce the Company's incentive for efficiency and cost minimization.[20] In his Report, the Administrative Law Judge (ALJ) contemplated a "one-time experiment" for allowing reagent costs in the FCA as a way to allow the Commission to test the proposition that the meaningful incentives to contain reagent costs will be lost if the costs are included in the FCA.[21] The Commission concurred with the ALJ and approved recovery of reagent costs through the FCA. Further, the Department found numerous instances in which the Commission denied recovery of reagent costs through automatic adjustment of fuel charges and maintaining recovery through base rates.[22]

The Department recommends the Commission deny the Company's request to recover reagent costs through its FPE Rider as opposed to continued recovery in base rates.

[18] "FAC Reform" occurred December 2017. The Commission issued its *Order* in Docket No. E999/CI-03-802 on December 19, 2017 and also issued an *Order* revising implementation dated December 12, 2018.
[19] The Company filed its initial filings in Docket No. E015/GR-21-335 on November 1, 2021.
[20] *In re the Application of Otter Tail Power Co. for Authority to Increase Rates for Electric Service in Minn.*, MPUC Docket No. E017/GR-20-719, Ex. DER-13 at 23 (Johnson Surrebuttal). Note: Otter Tail Power refers to its fuel adjustment rider as Energy Adjustment Rider (EAR).
[21] *In re the Application of Otter Tail Power Co. for Authority to Increase Rates for Electric Service in Minn.*, MPUC Docket No. E017/GR-20-719, Findings of Fact, Conclusions of Law and Recommendation, at 84, Office of Administrative Hearings, September 20, 2021.
[22] Department Attachment 2, Commission Orders RE Reagent Costs

III. DEPARTMENT RECOMMENDATIONS

The Department appreciates the opportunity to comment on Minnesota Power's Petition.

The Department requests the Company provide the dollar amount in rebates the Company received for reagents since 2016 and if the Company included the rebate amounts as an offset to its costs.

The Department recommends the Commission deny the Company's Petition.

The Department is available for any questions the Commission may have.

How Should Regulators View Cost Trackers?

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.

Ken Costello

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The author thanks Scott Hempling and Adam Pollock, both of NRRI; Dr. Douglas N. Jones of Ohio State University; Michael McFadden of McFadden Consulting Group; Prof. Carl Peterson of the University of Illinois – Springfield; and Joseph W. Rogers of the Massachusetts Attorney General Office for their comments on an earlier draft of this article. Any errors remain the responsibility of the author.

I. Introduction

This article discusses the major issues regulators face in evaluating the costs and benefits of cost trackers.[1] This article 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.

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This article 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 article examines two scenarios; in the first, regulators allow comprehensive cost trackers, while in the second they allow none. The article ends by recommending a regulatory policy that considers a rate-of-return tracker in lieu of a medley of narrow-based cost trackers.

II. 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 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 article 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).

The unpredictability of a cost item means that test-year cost estimates can overstate or understate the actual costs.

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 utility's new investments in upgrading 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.

III. 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 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 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]

Without any expected benefits, management would exert minimum effort on cost containment.

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

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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.

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., fuel purchases, 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]

Commissions tend to avoid cost recovery that results in radical price volatility to utility customers.

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 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 baseload-generating facility.

IV. 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

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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), (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 utilities want to expand the scope of their FACs and 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.

Utilities have argued that a more dynamic market environment justifies the recovery of certain costs through a tracker rather than in base rates.

V. 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 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

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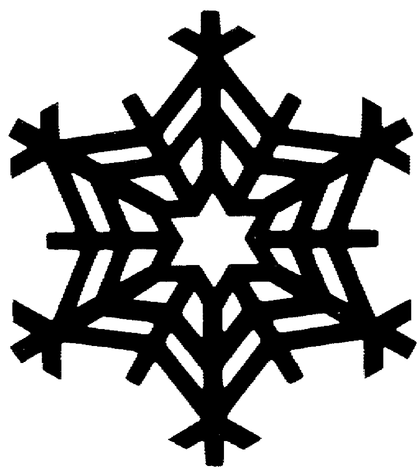
operating expenses to provide a "fair return" to investors. Businesses including utilities need to earn a profit to compensate investors for business, financial, and other risks.[26]

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]

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 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 opportunity 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

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other problems, which this article discusses in Section III.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]

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.

VI. 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

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recent market developments, including those affecting a utility's costs.[35] Compared to 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 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. 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 a cost tracker also depends upon the

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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?

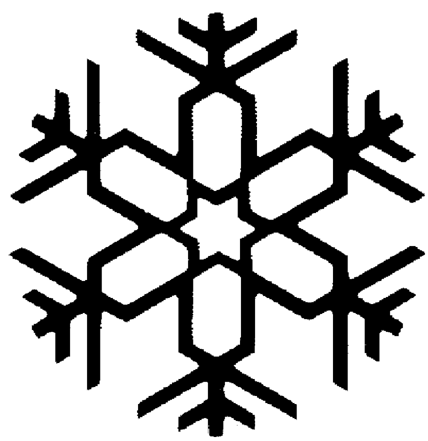
VII. Putting It All Together

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 article, 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]

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

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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.

This article 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]

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,

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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.■

Endnotes:

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 article 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.

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 and Peter Nagler, *Current PGA and FAC Practices: Implications for Ratemaking in Competitive Markets* (Columbus, Ohio: NRRI, Nov. 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 8TH NARUC BIENNIAL REGULATORY INFORMATION CONFERENCE (Columbus, Ohio: NRRI, Sept. 1992); Kevin A. Kelly, Timothy Pryor and Nat Simons, *Electric Fuel Adjustment Clause Design* (Columbus, Ohio: NRRI, 1979), NRRI 79-3; and Douglas N. Jones, Russell J. Profozich and Timothy Biggs, *Electric and Gas Utility Rate and Fuel Adjustment Clause Increases, 1978 and 1979* (Columbus, Ohio: NRRI, 1981), NRRI 81-5.

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 article 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 article 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 James F. Wilson, *A Hard Look at Incentive Mechanisms for Natural Gas Procurement*, NRRI 06-15, Nov. 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*, J. IND. ECON., Vol. 27 (1979): 243-69; David P. Baron and Raymond R. DeBondt, *On the Design of Regulatory Price Adjustment Mechanisms*, J. ECON. 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 ECON. J., 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*, ENERGY J., 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

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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 article, 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.

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

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 *supra* note 9.

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 electric utilities, the strong incentives for controlling fuel 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.

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 American Gas Foundation Executive Forum, held at Ohio State Univ., May 23, 2006.

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. I thank Carl Peterson for this insight.

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.

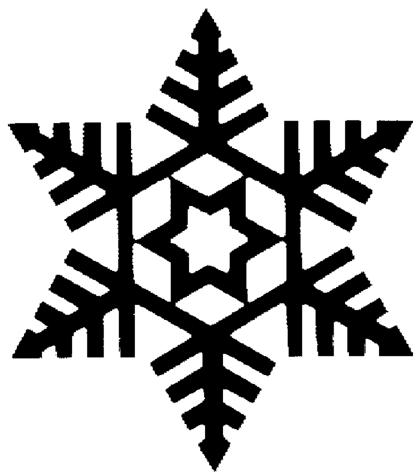
25. The U.S. Supreme Court outlined these conditions in its 1944 order for *FPC v. Hope Natural Gas Co.*, 320 U.S. 591, 605 (1944).

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. 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 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*, J. LAW & ECON., 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.

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.

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 certainly 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 acute if the commission believes that fortuitous circumstances, 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

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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.

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.

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 Univ. 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, Sept. 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.

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, Nov. 2008, at http://nrri.org/pubs/electricity/nrri_preapproval_commitments_08-12.pdf.

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 *supra* note 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 compares, among other things, the resources expended by the commission and non-utility stakeholders per dollar recovered under trackers and in a rate case.

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 frequently 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.

COMMERCE DEPARTMENT

Commission Orders denying reagent cost recovery through automatic adjustment of fuel charges and maintaining recovery through base rates:

1. Minnesota Power's 2016 Rate Case (Docket No. E015/GR-16-664) Findings of Fact, Conclusions and Order (March 12, 2018) at 47-48:

The Issue
Minnesota Power uses reagents and other chemicals to reduce pollution from its power plants. The test-year cost of reagents is approximately $4 million and is included in the Company's O&M budget.

Minnesota Power seeks permission to recover reagent costs through the fuel clause, arguing that such recovery is authorized by Minn. Stat. § 216B.16, subd. 7, which provides that the Commission "may permit a public utility to file rate schedules containing provisions for the automatic adjustment of charges for public utility service in direct relation to changes in . . . prudent costs incurred by a public utility for sorbents, reagents, or chemicals used to control emissions from an electric generation facility."

The Department opposed fuel-clause recovery, arguing that limiting recovery of reagent costs to base rates gives Minnesota Power an incentive to minimize these costs between rate cases. The ALJ agreed and recommended that the Commission deny the Company's request.

Commission Action
The Commission concurs with the ALJ and the Department and will not allow Minnesota Power to include reagent costs in the fuel-clause adjustment.

Minn. Stat. § 216B.16, subd. 7, allows the Commission to permit fuel-clause recovery of prudent reagent costs bud does not require it to do so. The Commission concludes that permitting such recovery is not in the public interest because it removes a major incentive for the Company to limit such costs between rates.

If an operational cost is recoverable solely through base rates, a utility can increase its profits only by minimizing that cost. However, if a cost is recoverable through the fuel clause, a utility knows that it can recover prudent costs that exceed the base costs, and thus has less incentive to control costs. For this reason, the Commission will deny fuel-clause recovery of reagent costs.

2. Otter Tail Power's 2015 Rate Case (Docket No. E017/GR-15-1033) Findings of Fact, Conclusions, and Order (May 1, 2017) at 30-32:

The Company also proposed to include test year reagent costs and emission allowance amounts in the base fuel cost amount, against which actuals would be measured in the energy

adjustment rider (also referred to as fuel clause adjustment). The Commission has previously denied a request by Otter Tail to include reagent costs in the rider.[1]
Otter Tail explained that any over- or under-recovery would be address through the annual fuel clause true-up process. The Department recommended that the Commission deny the Company's proposed recovery of reagent costs and emission allowances through the fuel clause adjustment.

Otter Tail
The Company explained that the consumption of reagents and the quantity of reagents used depends on the dispatch of the generating unit—i.e., when the plant is operating, it is consuming reagents. The variability of amount consumed is beyond the Company's control, and makes reagents appropriate for rider recovery.46 The Company also stated that similarly, plant emission levels depend on the hours of operation and dispatch levels of each plant, and are also appropriate for recovery through the base fuel amount with over- or under-recovery adjusted for through the fuel clause adjustment rider.

The Company proposed certain modifications to Section 13.01 of its Minnesota Electric Rate Schedule to address recovery of reagents and emissions-allowance expenses through the fuel clause adjustment rider, as well as the proceeds of any emission-allowance sales as a credit. Otter Tail argued that recovery in the fuel clause rider is appropriate, because the rate case has allowed comprehensive review of Company costs and revenues for prudence and reasonableness that the Commission found not available in Docket No. E-017/M-14-649.

The Department
The Department objected to the Company's proposal to true up the costs of reagents and emission allowances through the fuel clause adjustment rider.

The Department argued that Minn. Stat. § 216B.16, subd. 7, authorizes, but does not require, the Commission to permit automatic adjustment of charges for specified costs, including the cost of reagents. The Department argued that the Commission has previously considered this exact issue, and denied the Company's request to recover reagent costs and emission allowances through the fuel clause. The Department argued that there has been no material change in circumstances since the Commission issued its decision in that matter.

Further, the Department argued that it would be unreasonable to allow fuel clause recovery in this rate case. The Department asserted that while the Company demonstrated the reasonableness of reagent costs in this rate case, the Company's proposed cost recovery in the fuel clause would not be subject to such a comprehensive review, because the costs will automatically flow though the fuel clause rider and on to ratepayers.

Finally, the Department explained that the Commission has asked the Department and other parties to examine the fuel clause adjustment mechanism and to file a proposal for a more appropriate ratemaking mechanism than the automatic flow-through of cost changes in the fuel clause.

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[1] *In the Matter of Otter Tail Power's Request or Approval to Review Its Energy Adjustment Rider to Include Emission Control Costs,* Docket No. E017/M-17-649, Order Denying Petition to Revise Energy Adjustment Rider and Denying Variance Request (May 27, 2015).

Recommendations of the Administrative Law Judge

The ALJ recognized that reagent costs, once placed in the fuel clause adjustment rider, could change between rate cases to the detriment of ratepayers. The ALJ also recognized that if the variable expense experienced—whether due to the dispatch of the generation units or fluctuations in commodity price—is lower than the amount of costs placed in the test year as fixed costs, an over payment could occur.

The ALJ found the Company's proposal to be the lower risk alternative, and recommended that the Commission include test year reagent cost and emission allowance amounts as part of the base fuel cost of the fuel clause adjustment, with any over-or under-recovery addressed through the annual true-up process.

Commission Action

The Commission respectfully disagrees with the ALJ's recommendations on this issue. The Commission concurs with the Department, and will deny the Company's request. Accordingly, the Commission will adopt certain revised findings and conclusions as set forth below and in the ordering paragraphs.

Minn. Stat. § 216B.16, subd. 7, authorizes, but does not require, the Commission to permit the automatic adjustment of charges for specified costs. Importantly, Minn. Stat. § 216B.03 continues to require that all rates, including the fuel clause adjustment, be just and reasonable and that "[a]ny doubt as to reasonableness should be resolved in favor of the consumer."

The Commission has previously considered this issue. In Docket No. E-017/M-14-649, the Commission determined that allowing recovery of all reagent costs through the fuel clause, without the careful review of costs as would occur in a rate case, would not be reasonable, and would likely reduce Otter Tail's incentive for efficiency and cost minimization. Otter Tail has not proved in this rate case that its request to recover all costs of reagents through its fuel clause adjustment rider would be reasonable.

Accordingly, the Commission will not authorize Otter Tail to include test-year reagent cost and emission-allowance amounts in the base fuel cost, or to adjust test-year reagent costs and emission-allowance amounts through the fuel clause.

3. Otter Tail Power's 2020 Rate Case (Docket No. E017/GR-20-719) Findings of Fact, Conclusions and Order (February 1, 2022) at 27-29:

Introduction

The Energy Adjustment Rider (EAR) reconciles the difference between energy costs recovered in base rates and the actual costs incurred by the utility; if actual costs exceed the costs in base rates, customers are charged for the difference, and if the costs in base rates exceed the actual cost, the excess is returned to customers. This is a monthly adjustment, and accounts for variations in energy costs that occur outside of the rate case process.

Otter Tail made several recommendations regarding the EAR in this rate case, and two of those recommendations are disputed.

First, Otter Tail requested to include the cost of chemical reagents in the EAR. Chemical reagents are used to process emissions and are necessary for the Company to comply with federal air quality regulations. In 2011, Minn. Stat. § 216B.16, subd. 7, was changed to allow for reagent costs to be included in the EAR, provided that these costs were not recovered elsewhere in rates. However, in Otter Tail's 2015 rate case, the Commission denied recovery for reagent costs because they could not be carefully reviewed under the then-existing EAR mechanism.

Otter Tail stated that the EAR has since been significantly reformed and that the new mechanism does provide for careful review of all forecasted costs.

Second, Otter Tail requested to include the costs and revenues from steam and water sales in the EAR. Otter Tail sells steam and water from its Big Stone Plant to POET Biorefining. Previously, these costs and revenues were not included in the EAR. However, the Company explained that since its 2015 rate case, the Big Stone Plant has been operating on an economic dispatch basis, meaning that the plant will only operate if its relative cost is lower than competing resources or if it must be run to ensure reliability. The Company argued that this makes steam and water sales more variable, and that it is now appropriate to include these costs and revenues in the monthly EAR.

Position of the Parties

The Department opposed inclusion of the reagent costs in the EAR, arguing that the statutory authority for including this cost in the EAR is permissive, not mandatory, and that no other Minnesota utility recovers reagent costs in this way. Additionally, the Department stated that allowing the Company to recover reagent costs in the EAR could reduce its incentive for efficiency and cost control, since price increases would be recovered from customers much more quickly than if base rates remained the only avenue for recovery.

The Department also opposed the inclusion of costs and revenues from the POET Biorefining steam and water sales in the EAR. Specifically, the Department argued that the changes to the EAR did not contemplate recovery of fuel costs related to steam and water sales, and that the EAR reform process did not provide the opportunity for careful review that the Company had asserted. Furthermore, the Department noted that other utilities do not include any such costs in the EAR.

Recommendation of the Administrative Law Judge

The ALJ recommended including both reagent costs, and steam and water sale costs and revenues, in the EAR. The ALJ stated that the legislature "clearly" intended the Commission to consider the inclusion of reagent costs in the EAR when it amended Minn. Stat. § 216B.16, subd. 7, to explicitly address those costs. The ALJ suggested that inclusion of reagent costs in the EAR could be considered an "experiment" to test whether the incentive to reduce reagent costs would be lost; when Otter Tail's final rates are implemented, the Commission can track whether the Company's reagent costs rise compared to those of other Minnesota utilities.

The ALJ also pointed out that including both reagent costs and POET revenues and fuel costs in the EAR would recognize and support the reduction in use of coal-fired generation resources under the economic dispatch model by reducing the regulatory and cost risk for utilities to use this model.

Overall, the ALJ found that Otter Tail's proposal to include reagent costs and POET steam and water sales in the EAR was reasonable and should be adopted.

Commission Action
The Commission concurs with the ALJ and will approve recovery of reagent costs and POET revenues and fuel costs through the EAR. Although the Commission did deny EAR recovery of reagent costs in Otter Tail's last rate case, circumstances have changed; the Company's dispatch model has moved to increasing reliance on economic dispatch, leading to greater variability in reagent costs. Additionally, the Legislature has clearly contemplated the possibility of reagent cost recovery in the EAR and it is appropriate to allow it in this case. If reagent costs do begin to rise disproportionately, the Commission will have the opportunity to investigate further and modify recovery in future EAR proceedings.

Similarly, it is reasonable to approve recovery of POET revenues and fuel costs through the EAR. As noted by the ALJ, the Commission supports the reduction in use of coal-fired generation resources under the economic dispatch model. The Commission seeks to encourage and reinforce this positive progress. However, the EAR review process includes ample opportunity to analyze and modify cost recovery if necessary to protect ratepayer interests.

4. Otter Tail Power's 2014 Energy Adjustment Rider Case (Docket No. E017/GR-14-649) Order Denying Petition to Revise EAR and Denying Variance Request (May 2017, 2015) at 3-4:

III. Reagent Costs

A. Positions of the Parties

1. Otter Tail

Otter Tail proposed to recover, through its Energy Adjustment Rider, the costs of the three reagents used to control emissions and meet EPA's MATS compliance obligations—powdered activated carbon, anhydrous ammonia, and pebble lime—at its Big Stone, Coyote Station, and Hoot Lake plants. Otter Tail made its request under Minn. Stat. § 216B.16, subd. 7(4). The Company argued that the new statute provides specific statutory authority to recover reagent costs through the Energy Adjustment Rider, and that it is the best long-term mechanism to recover these types of costs.

Otter Tail estimated that the Minnesota share of the reagent costs necessary to operate the three plants in compliance with the MATS rule is some $1,674,998. The Company stated that in an effort to control cost volatility of the reagents, it has, in advance of need, contracted for the supply of all new reagents and locked in commodity prices.

Otter Tail also provided background on two prior Commission proceedings that it argued support the treatment of the reagent and emission allowance costs requested here—the Advance Determination of Prudence of costs associated with installing emissions control equipment at the Big Stone Plant, and the Baseload Diversification Study ordered as part of the Company's 2010 Integrated Resource Plan.[2] The Company argued that technologies approved in these two proceedings contemplated incurring the reagent costs discussed in this proceeding, and that these costs should be allowed.

2. The Department

The Department opposed Otter Tail's request to include reagent costs in the Energy Adjustment Rider. The Department argued that while the Minnesota Legislature now allows reagent costs to be recovered by rider under Minn. Stat. § 216B.16, subd. 7(4), cost recovery under the rule is at the discretion of the Commission. Further, the Department emphasized that Minn. Stat. § 216B.03 continues to require that all rates, including those recovered by rider, "shall be just and reasonable and that any doubt as to reasonableness should be resolved in favor of the consumer."

The Department asserted that to allow a utility to recover all costs of reagents without prior comprehensive review of costs would reduce a utility's incentive for efficiency and cost minimization. Further, the Department argued that allowing direct recovery of such costs between rate cases could result in utilities failing to consider those costs critically as an integrated part of their cost of business.

The Department also argued that the amount of reagent expense currently in base rates can reasonably be considered to be representative of all reagent costs, and should not be adjusted between rate cases, at least without making a clear showing that the costs for which recovery is sought are reasonable. The Department emphasized that the Company has provided no mechanism by which to make the required showing of reasonableness.

Finally, the Department argued that the Company's attempt to use the Commission's prior decisions on its request for an Advance Determination of Prudence docket and its Baseload Diversification Study submitted as part of the Company's 2010 Integrated Resource Plan to bolster the prudence of its position in this matter is unconvincing and irrelevant. The Department argued that neither proceeding included a determination by the Commission that Otter Tail would be entitled to recover reagent costs through its Energy Adjustment Rider.

B. Commission Action

The Commission concurs with the Department that Otter Tail's request to recover reagent costs associated with its compliance with the Environmental Protection Agency's MATS rules through its Energy Adjustment Rider should be denied.

In making this determination, the Commission recognizes the fundamental precept that a utility may not generally change its rates without a rate case proceeding, in which the Commission comprehensively reviews the utility's costs and revenues for prudence and reasonableness. Otter Tail's last rate case was in 2010,[3] and the Company has indicated that it is not likely to file

[2] See Docket Nos. E-017/M-10-1082 and E-017/RP-10-623.
[3] Docket No. E-017/GR-10-239.

another rate case for several years, severely limiting the opportunity for meaningful review of these costs.

Further, Minn. Stat. § 216B.16, subd. 7, authorizes, but does not require, the Commission to permit the automatic adjustment of charges for specified costs. And, importantly, Minn. Stat. § 216.03 continues to require that all rates, including the fuel clause adjustment, be just and reasonable and that "[a]ny doubt as to reasonableness should be resolved in favor of the consumer."

The Commission finds that to allow Otter Tail to recover all costs of reagents through its Energy Adjustment Rider without a careful review of costs would not be reasonable, and would likely reduce its incentive for efficiency and cost minimization. At this early stage in the MATS compliance process, it is important to ensure that the Company view these costs as an integral part of the cost of doing business—subjecting them to the same fiscal discipline as other basic costs—rather than add-on costs automatically passed through to ratepayers.

Further, the Commission has considered the pertinence of the two prior proceedings cited by the Company – the Advance Determination of Prudence and the Baseload Diversification Study. The Commission concurs with the Department that the two proceedings do not provide useful guidance here, since neither case analyzed the cost recovery issues associated with the purchase of reagents.

5. Xcel's 2013 Rate Case (Docket No. E002/GR-13-868) Stephen H. Mills (Xcel) Evidentiary Hearing Opening Statement (August 25, 2014) and Nancy Campbell (DOC) Evidentiary Hearing Testimony (August 25, 2014) at 30-32:

Mills Evidentiary Hearing Opening Statement

Good morning. My name is Steven Mills and I am Vice President of Energy Supply Operations for Xcel Energy Service Inc. In this role, I am responsible for all fossil and renewable operations throughout the Xcel Energy generation fleet.

In this case, I sponsored testimony supporting the Company's request of approximately $117.9 million for Energy Supply O&M expenses in 2014 as well as an incremental approximately $5.8 million in O&M expenses for 2015, all on a Minnesota jurisdictional basis. This includes the Company's 2014 Test Year and 2015 Step emissions chemicals costs. While the Company continues to believe that the most effective way to address these costs is through the use of the Fuel Clause Adjustment rider, it is my understanding that the Company is accepting the Department's proposed adjustment for our emissions chemicals costs for 2014 in an effort to limit contested issues in this case. Further, based on discussions with the Department the Company is proposing an adjustment equal to half of Ms. Campbell's proposed adjustment for our 2015 Step request related to mercury sorbent costs for Sherco 1 and 2. Company witness Ms. Heuer will quantify this adjustment in her opening statement. The Company believes that this is a reasonable resolution to this contested issue given our lack operating experience with the wet-scrubber emissions control technology being deployed at Sherco 1 and 2 and the uncertainty surrounding it. It is my understanding that the Department supports this proposal.

My testimony in this case also provides support for the Company's proposed $54.6 million in capital additions for the Energy Supply business area in 2014 on a Minnesota jurisdictional basis. I also support the Company's 2015 step request of approximately $26.6 million in capital additions on a Minnesota jurisdictional basis for Energy Supply capital projects.

I also provided information for the record in this proceeding related to the Energy Supply Operating Model, our plant performance, and other operational aspects of the Company's non-nuclear generation fleet.

Thank you.

Campbell Evidentiary Hearing Testimony (p. 2)

5. Emission Control Chemicals for 2014 and 2015:
Based on the opening statement of Xcel witness Mr. Steven Mills, the Company now agrees to my recommended adjustment of a $2.265 million reduction on a Minnesota jurisdictional basis to emission chemicals costs for 2014. The Company also agrees with my recommendation not to recover the emission chemical costs via the FCA. DOC Ex. 435 at 31 (Campbell Public Surrebuttal).

Based on the opening statement of Mr. Mills, the Company now also agrees to $1.4 million reduction (or 50 percent of the $2.8 million reduction I recommended in my surrebuttal testimony) on a Minnesota jurisdictional basis to emission chemicals for 2015. I agree that this proposal would reasonably resolve the issue of the appropriate level of 2015 emissions costs in this proceeding; thus, I recommend that the Commission approve this proposal.

CERTIFICATE OF SERVICE

I, Sharon Ferguson, hereby certify that I have this day, served copies of the following document on the attached list of persons by electronic filing, certified mail, e-mail, or by depositing a true and correct copy thereof properly enveloped with postage paid in the United States Mail at St. Paul, Minnesota.

Minnesota Department of Commerce
Public Response Comments

Docket No. E015/M-22-547

Dated this **11th** day of **January 2023**

/s/Sharon Ferguson

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Generic Notice	Commerce Attorneys	commerce.attorneys@ag.state.mn.us	Office of the Attorney General-DOC	445 Minnesota Street Suite 1400 St. Paul, MN 55101	Electronic Service	Yes	OFF_SL_22-547_M-22-547
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