

**BEFORE  
THE PUBLIC UTILITIES COMMISSION OF OHIO**

In the Matter of the Application of Duke )  
Energy Ohio for Authority to Establish a )  
Standard Service Offer Pursuant to Section )  
4928.143, Revised Code, in the Form of ) Case No. 14-841-EL-SSO  
an Electric Security Plan, Accounting )  
Modifications and Tariffs for Generation )  
Service. )

In the Matter of the Application of Duke )  
Energy Ohio for Authority to Amend its ) Case No. 14-842-EL-ATA  
Certified Supplier Tariff, P.U.C.O. No. 20. )

**PUBLIC VERSION**

**DIRECT TESTIMONY  
OF  
JEROME D. MIERZWA**

**On Behalf of the  
Office of the Ohio Consumers' Counsel**  
*10 West Broad St., Suite 1800  
Columbus, OH 43215*

**SEPTEMBER 26, 2014**

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**I. INTRODUCTION AND QUALIFICATIONS**

***Q1. WOULD YOU PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.***

***A1.*** My name is Jerome D. Mierzwa. I am a principal and President of Exeter Associates, Inc. ("Exeter"). My business address is 10480 Patuxent Parkway, Suite 300, Columbia, Maryland 21044. Exeter specializes in providing public utility-related consulting services.

***Q2. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.***

***A2.*** I graduated from Canisius College in Buffalo, New York, in 1981 with a Bachelor of Science Degree in Marketing. In 1985, I received a Master's Degree in Business Administration with a concentration in finance, also from Canisius College. In July 1986, I joined National Fuel Gas Distribution Corporation ("NFGD") as a Management Trainee in the Research and Statistical Services Department ("RSS"). I was promoted to Supervisor RSS in January 1987. While employed with NFGD, I conducted various financial and statistical analyses related to the Company's market research activity and state regulatory affairs.

In April 1987, as part of a corporate reorganization, I was transferred to National Fuel Gas Supply Corporation's ("NFG Supply") rate department where my responsibilities included utility cost of service and rate design analysis, expense and revenue requirement forecasting and activities related to federal regulation. I was also responsible for preparing NFG Supply's Purchased Gas Adjustment ("PGA") filings and developing interstate pipeline and spot market supply gas price

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1 projections. These forecasts were utilized for internal planning purposes as well as in  
2 NFGD's purchased gas cost review proceedings.

3  
4 In April 1990, I accepted a position as a Utility Analyst with Exeter. In December  
5 1992, I was promoted to Senior Regulatory Analyst. Effective April 1, 1996, I  
6 became a principal of Exeter. Since joining Exeter, I have specialized in evaluating  
7 the gas purchasing practices and policies of natural gas utilities, revenue requirement  
8 analysis, utility class cost of service and rate design analysis, sales and rate  
9 forecasting, performance-based incentive regulation, the unbundling of utility  
10 services and evaluation of customer choice natural gas transportation programs.

11  
12 *Q3. HAVE YOU PREVIOUSLY TESTIFIED IN REGULATORY PROCEEDINGS ON*  
13 *UTILITY RATES?*

14 *A3.* Yes. I have provided testimony on more than 200 occasions in proceedings before  
15 the Federal Energy Regulatory Commission ("FERC"), and utility regulatory  
16 commissions in Delaware, Georgia, Illinois, Indiana, Louisiana, Maine, Maryland,  
17 Montana, Nevada, New Jersey, Pennsylvania, Rhode Island, Texas and Virginia, as  
18 well as before the Public Utilities Commission of Ohio ("PUCO").

**II. PURPOSE OF TESTIMONY**

***Q4. WHAT IS THE PURPOSE OF YOUR TESTIMONY?***

*A4.* On May 29, 2014, Duke Energy Ohio, Inc. ("Duke" or "the Utility") submitted an application with the PUCO seeking approval of a new electric security plan ("ESP") for the period June 1, 2015 through May 31, 2018. As part of its application, Duke is proposing a Distribution Capital Investment Rider ("Rider DCI") and a Distribution Storm Rider ("Rider DSR"). Exeter was retained by the Office of the Ohio Consumers' Counsel ("OCC") to evaluate Riders DCI and DSR.

***Q5. PLEASE SUMMARIZE THE RESULTS OF YOUR EVALUATION OF THESE RIDERS.***

*A5.* Riders DCI and DSR should not be approved by the PUCO for the reasons set forth in my testimony.

**III. IMPLEMENTATION OF RIDERS**

***Q6. AS A GENERAL MATTER, DO YOU AGREE WITH THE CONCEPT OF RIDERS?***

*A6.* No. Riders (also referred to as "trackers," "cost trackers" or "reconciliation mechanisms") allow regulated utilities to collect designated costs from customers outside of the context of a traditional base rate proceeding, where all elements of the cost of service are examined. As a general matter, riders that provide for the

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1 automatic collection of certain costs from customers are contrary to sound ratemaking  
2 principles. When a utility is permitted to collect costs through a rider, the incentive  
3 for the utility to control costs tends to be reduced or eliminated. As subsequently  
4 discussed, a rider can even potentially give a utility a perverse incentive to make  
5 uneconomic choices.

6 Because of these potential problems, to the extent that riders are approved, they  
7 should be limited to cost items that are substantial, unpredictable, generally beyond  
8 the utility's control, and not essential to protecting a utility from a dire financial  
9 situation. Examples of costs for which a rider could be appropriate are purchased gas  
10 costs for a gas distribution utility or fuel and purchased power for an integrated  
11 electric utility like Duke.

12 Duke has presented little evidence that the costs that it is seeking to collect through its  
13 proposed riders meet these criteria (costs that are substantial, unpredictable, and  
14 outside of the utility's control). Additionally, Duke has not shown that its financial  
15 integrity would be compromised if those costs could be collected only through a  
16 traditional base rate proceeding where the costs would be subject to closer scrutiny.  
17 A report by the National Research Regulatory Institute ("NRRRI") titled "*How Should*  
18 *Regulators View Cost Trackers?*" (September 2009) presents a concise and balanced  
19 description of the regulatory issues associated with riders, and I have attached a copy  
20 of this report to my testimony (JDM Attachment-1).

1 *Q7. BRIEFLY SUMMARIZE THE FINDINGS OF THE NRRI REPORT WITH*  
2 *RESPECT TO REGULATORY POLICY AND THE USE OF RIDERS.*

3 *A7.* The NRRI report found that “Good regulatory policy rejects cost trackers that are not  
4 essential for protecting a utility from a dire financial situation.” (JDM Attachment-1,  
5 page 14).  
6

7 *Q8. PLEASE EXPLAIN HOW RIDERS CAN POTENTIALLY RESULT IN*  
8 *UNECONOMIC INCENTIVES FOR A REGULATED UTILITY, WHICH THEN*  
9 *TRANSLATES INTO HIGHER RATES FOR CUSTOMERS?*

10 *A8.* Suppose that a regulated utility was faced with a decision between either replacing a  
11 piece of equipment or contracting to maintain the equipment. From a present value  
12 perspective it might be more economical to incur the cost to maintain the equipment  
13 rather than replace it. However, if the utility has a rider where it can automatically  
14 recover the cost of plant additions but would have to “absorb” any incremental  
15 maintenance expense under its existing base rates, then there is obviously an  
16 incentive to make the replacement even though that might not be the more economic  
17 option.  
18

19 *Q9. ARE THERE ANY OTHER POTENTIAL CONCERNS WITH COLLECTION OF*  
20 *COSTS FROM CUSTOMERS THROUGH RIDERS?*

21 *A9.* Yes. The collection of costs from customers through riders can lead to increases in  
22 utility rates and revenues (collected by the utility) even when a regulated utility does  
23 not have a revenue deficiency. By contrast, in the absence of riders, a regulated

1 utility would be able to implement rate increases only after a comprehensive base rate  
2 proceeding where all costs and the revenues under present rates were taken into  
3 consideration. If it were determined that the rates in effect were already producing an  
4 adequate return, then no rate increase would be authorized.

5  
6 **IV. DISTRIBUTION CAPITAL INVESTMENT RIDER**

7  
8 *Q10. PLEASE DESCRIBE DUKE'S PROPOSED RIDER DCI.*

9 *A10.* Rider DCI, as proposed in Duke's application, is designed to recover a return on  
10 incremental capital investment and the associated depreciation and property taxes for  
11 distribution-related investment that is not otherwise recovered through base rates or  
12 another rider regardless of the Utility's level of earnings. As proposed all capital  
13 investment (excluding that recovered through Rider DR-IM, Infrastructure  
14 Modernization Rider) recorded in FERC Plant accounts 360 through 374 will be  
15 included in Rider DCI. In addition, the portion of the electric common general plant  
16 in FERC Plant accounts 303 and 389 through 398 that are allocated to distribution  
17 will also be included. In its application, Duke identifies 19 capital improvement  
18 programs that it intends to pursue and the costs associated with those 19 programs.  
19 However, the costs to be recovered under Rider DCI are not limited to those  
20 associated with these 19 projects, and there is no limit to the increase in net  
21 distribution and common general plant investment which can be made by Duke and



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1 recovered under Rider DCI. That is, there is no limit to the rate increases customers  
2 could experience under Rider DCI.

3  
4 ***Q11. WHAT RATE OF RETURN WILL BE APPLICABLE TO THE INCREMENTAL***  
5 ***CAPITAL INVESTMENT RECOVERED THROUGH RIDER DCI?***

6 ***A11.*** The rate of return grossed up for taxes would be based on the weighted average cost  
7 of capital and gross revenue conversion factor approved in Duke's most recent  
8 distribution base rate case (Case No. 12-1682-EL-AIR), which is currently 10.7  
9 percent. Included in the rate of return is a 9.84 percent return on equity. While I do  
10 not address the appropriateness of this rate of return, OCC Witness Mathew I. Kahal  
11 does.

12  
13 ***Q12. WHAT PROCEDURAL TIMELINE IS DUKE PROPOSING FOR RIDER DCI?***

14 ***A12.*** Duke is proposing to make quarterly filings to adjust rates under Rider DCI. Filings  
15 would be made at least 60 days prior to the effective date. Rates would be based on  
16 projected costs as of the rate effective date. For example, an adjustment to rates  
17 under Rider DCI to be effective January 1, 2015 would be made no later than  
18 November 1, 2014, and the rate adjustment would be based on projected costs as of  
19 December 31, 2014.

20  
21 ***Q13. WHY IS DUKE PROPOSING RIDER DCI?***

22 ***A13.*** Duke witness Marc W. Arnold claims that the Utility's current planning and  
23 operation and maintenance practices and programs coupled with the current level of

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1 spending for equipment replacement are not sufficient for Duke to maintain its  
2 present level of service reliability and meet customer expectation. Witness Arnold  
3 claims that customers are demanding increasing service reliability. To enable what  
4 the Utility contends is the necessary investment in its distribution system and  
5 allowing for the timely recovery of the costs associated with that investment, Duke is  
6 proposing Rider DCI.

7  
8 ***Q14. WHAT IS THE ESTIMATED IMPACT OF RIDER DCI ON DISTRIBUTION***  
9 ***BASE RATES?***

10 ***A14.*** The estimated increase in distribution rates resulting from Rider DCI is presented in  
11 Table 1. As shown on Table 1, Duke is proposing to increase distribution rates by  
12 \$104 million over four years. For the average residential customer, this would reflect  
13 an increase in rates of nearly \$100 per year by 2018.

<b>Table 1</b> <b>Impact of Rider DCI on Distribution Rates</b> <b>(millions)<sup>1</sup></b>		
Year	Increase	
	Annual	Cumulative
2015	\$22	\$22
2016	41	63
2017	20	83
2018	21	104

14  

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<sup>1</sup> Response to OCC-INT-02-010.

1    ***Q15. HAS DUKE DEMONSTRATED THAT ITS CURRENT PRACTICES AND***  
2           ***PROGRAMS COUPLED WITH CURRENT SPENDING LEVELS ARE NOT***  
3           ***SUFFICIENT TO MAINTAIN ITS PRESENT LEVEL OF SERVICE***  
4           ***RELIABILITY TO ITS CUSTOMERS?***

5    ***A15.*** No. Therefore, Duke has not justified that it is necessary to increase the rates of its  
6           customers through Rider DCI to maintain the present the level of service reliability.

7

8    ***Q16. HAS DUKE DEMONSTRATED THAT RELYING UPON THE TRADITIONAL***  
9           ***BASE RATE SETTING PROCESS TO COLLECT THE COSTS ASSOCIATED***  
10          ***WITH ANY NECESSARY INCREMENTAL DISTRIBUTION SYSTEM***  
11          ***INVESTMENT WILL PUT IT IN A DIRE FINANCIAL SITUATION?***

12   ***A16.*** No. Therefore, Duke has not demonstrated that Rider DCI is necessary to avoid  
13          putting it in a dire financial situation.

14

15   ***Q17. HAS DUKE PRESENTED ANY EVIDENCE THAT RELYING UPON THE***  
16          ***TRADITIONAL BASE RATE SETTING PROCESS HAS ADVERSELY***  
17          ***IMPACTED THE RELIABILITY OF ITS DISTRIBUTION SYSTEM, TO THE***  
18          ***DETRIMENT OF ITS CUSTOMERS?***

19   ***A17.*** No, it has not, and in fact and as subsequently explained, the reliability of Duke's  
20          distribution system has been increasing under the traditional base rate setting process.

1 *Q18. HAS DUKE PRESENTED ANY ANALYSES OR EVALUATION OF THE*  
2 *EXTENT TO WHICH THE RELIABILITY OF ITS DISTRIBUTION SYSTEM*  
3 *WILL IMPROVE UNDER RIDER DCI?*

4 *A18.* No. Therefore, the reasonableness of Duke's incremental system reliability  
5 investments cannot be determined.

6  
7 *Q19. IS THERE EVIDENCE THAT UNDER THE TRADITIONAL BASE RATE*  
8 *SETTING PROCESS DUKE HAS NOT BEEN ABLE TO MAINTAIN OR*  
9 *IMPROVE THE RELIABILITY OF ITS DISTRIBUTION SYSTEM FOR ITS*  
10 *CUSTOMERS?*

11 *A19.* No. Duke witness Arnold describes three standards for measuring system reliability:

- 12 • System Average Interruption Frequency Index ("SAIFI").  
13 The SAIFI measures the average number of service  
14 interruption per customer.
- 15 • System Average Interruption Duration Index ("SAIDI").  
16 The SAIDI is a measure of the average time each customer  
17 is interrupted.
- 18 • Customer Average Interruption Duration Index ("CAIDI").  
19 The CAIDI is the average time required to restore a service  
20 interruption measured on a per interrupted customer basis.<sup>2</sup>

21 Attached to my testimony as JDM Attachment-2 is a discovery response providing a  
22 history of the values of Duke's distribution system SAIFI, CAIDI, and SAIDI since  
23 2005. As shown there, Duke's SAIFI, which reflects the average number of service  
24 interruptions per customer, excluding storms, has declined from 1.49 in 2005 to 0.98

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<sup>2</sup> Direct testimony of Marc W. Arnold, p. 7.

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1 in 2013 or by nearly 35 percent, thus improving service reliability. The PUCO's  
2 performance standard for the SAIFI is 1.24.

3 Duke's SAIDI, or the average length of time each customer is interrupted has also  
4 improved recently. Duke's SAIDI, excluding storms, averaged 130.03 for the period  
5 2005-2011, and declined to an average of 113.58, or by 13 percent for the  
6 period 2012-2013. The only index not reflecting improvement since 2005 is the  
7 CAIDI, which is a measure of the average time to restore a service interruption. For  
8 the period 2005-2011 Duke's CAIDI, excluding storms, averaged 97.49 and increased  
9 to an average of 110.53 for the period 2012-2013. Despite this increase, Duke's most  
10 recent CAIDI of 117.80 is better than the PUCO's performance standard of 118.14.  
11 Because Duke is experiencing improvements in the SAIFI and SAIDI, there is no  
12 demonstration that the current method of capital funding for infrastructure is  
13 insufficient or inadequate.

14  
15 ***Q20. DESPITE THESE SERVICE RELIABILITY IMPROVEMENTS MR. ARNOLD***  
16 ***CLAIMS THAT DUKE'S CUSTOMERS ARE DEMANDING INCREASING***  
17 ***SERVICE RELIABILITY. WHAT IS THE BASIS FOR THESE CLAIMS?***

18 ***A20.*** Duke subscribes to and has participated in J.D. Power annual electric utility  
19 residential customer and business customer satisfaction studies. At the direction of  
20 the PUCO, Duke also performs a quarterly survey of customer satisfaction. Mr.  
21 Arnold claims that the Utility gauges its performance in relation to customer  
22 expectations and satisfaction based upon the results of these surveys. Although Mr.  
23 Arnold does not explicitly so state, it is logical to conclude from his testimony that

Duke strives to maintain or increase its customer satisfaction levels, and doing so would generally be considered a reasonable goal for any utility.

***Q21. MR. ARNOLD CLAIMS THAT THE J.D. POWER STUDIES SUPPORT THE CONCLUSION THAT CUSTOMERS ARE DEMANDING MORE RELIABLE SERVICE. UPON WHAT IN THOSE STUDIES IS MR. ARNOLD RELYING TO SUPPORT HIS CLAIM?***

***A21.*** Mr. Arnold claims that the J.D. Power 2013 Electric Utility Residential Customer Satisfaction Study<sup>SM</sup> ("J.D. Power 2013 Residential Study") supports the conclusion that customer outage tolerances are [REDACTED] while [REDACTED]. He claims that on a national average, overall satisfaction is [REDACTED] to [REDACTED], even among customers who experience no outages. Mr. Arnold concludes that customer expectations are high with respect to service reliability and power quality.

***Q22. WHAT IS YOUR RESPONSE TO MR. ARNOLD'S CLAIMS WITH RESPECT TO THE FINDINGS OF THE J.D. POWER 2013 RESIDENTIAL STUDY?***

***A22.*** The J.D. Power 2013 Residential Study measures customer satisfaction with electric utility companies by examining six factors:

- Price
- Power quality and reliability
- Billing and payment
- Corporate citizenship
- Communications

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- 1                   •       Customer service

2           Mr. Arnold only considers one of these factors, “power quality and reliability”. He  
3           fails to consider the overall impact of price on customer satisfaction as a result of the  
4           estimated \$104 million increase in rates which will occur under Rider DCI. A J.D.  
5           Power press release attached to my testimony on the 2013 Residential Study indicates  
6           that declines in power quality and reliability do not necessarily result in declines in  
7           customer satisfaction. (JDM Attachment-3.) The press release states:

8                   Despite ongoing severe weather across the United States resulting  
9                   in longer outage periods per event, customer satisfaction with  
10                  residential electric utilities has increased substantially from 2012  
11                  driven primarily by improvement in billing/payment, price and  
12                  outage communications, according to the J.D. Power 2013 Electric  
13                  Utility Residential Customer Satisfaction Study<sup>SM</sup> released today.

14

15    ***Q23. IS PRICE AN IMPORTANT DRIVER OF CUSTOMER SATISFACTION?***

16    *A23.* Yes. Price is a key driver of customer satisfaction, and customer perceptions can be  
17           impacted by price. For example, everyone wants better quality service but how much  
18           they want better quality service is directly related to what it would cost to provide  
19           better quality service.

20

21    ***Q24. DO YOU HAVE ANY OTHER OBSERVATIONS CONCERNING THE J.D.***  
22           ***POWER 2013 RESIDENTIAL STUDY?***

23    *A24.* Yes. The J.D. Power 2013 Residential Study places equal weight on each factor to  
24           determine overall customer satisfaction levels. The J.D. Power 2013 Residential  
25           Study does not account for the varying levels of importance of each factor. This fails

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1 to give appropriate consideration to price. In addition, the support for Mr. Arnold's  
2 claims are national averages, which may not be reflective of the sentiments of Duke's  
3 customers. Instead of focusing on the national perspective, I discuss the findings of  
4 the surveys conducted by Duke with respect to the factors considered important to  
5 Duke's customers next in my testimony. I believe the results of Duke's customer  
6 surveys should be given greater consideration than national perspectives because they  
7 are more reflective of the actual satisfaction levels of Duke's customers.

8  
9 ***Q25. MR. ARNOLD CLAIMS THAT THE SURVEYS PERFORMED BY DUKE AT***  
10 ***THE PUCO'S DIRECTION SUPPORTS THE CONCLUSION THAT***  
11 ***CUSTOMERS ARE DEMANDING MORE RELIABLE SERVICE. UPON WHAT***  
12 ***IN THOSE SURVEYS DOES HE RELY UPON TO SUPPORT THOSE CLAIMS?***

13 ***A25.*** Mr. Arnold claims that these surveys show that Duke's customers have very high  
14 expectations related to the number and duration of outages. But, he does not indicate  
15 how these surveys support the notion that customers have increasing expectations of  
16 reliability and power quality. More importantly, he does not identify whether  
17 customers are willing to pay an additional price associated with increased service  
18 reliability.

19  
20 ***Q26. WHAT IS YOUR INITIAL RESPONSE TO THE CLAIM THAT CUSTOMER***  
21 ***EXPECTATIONS REGARDING SERVICE RELIABILITY ARE INCREASING?***

22 ***A26.*** As explained earlier, Duke's SAIFI and SAIDI, two measures of reliability, have  
23 shown improvement since 2005. Therefore, under the current traditional base rate



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1 setting process, customers are receiving the increased service reliability the Utility  
2 claims they are demanding. In addition, the surveys performed by Duke asked  
3 customers how much they would be willing to pay to avoid interruptions of various  
4 durations (i.e., one hour, two hours, four hours).

5  
6 Approximately 50 percent of residential customers indicated they would not be  
7 willing to pay any additional costs to avoid service interruptions and for increased  
8 service reliability over today's service reliability standards (Attachment MWA-5).

9 Approximately 60 percent of business customers indicated they would not be willing  
10 to pay anything further to avoid service interruptions and for increased service  
11 reliability (Attachment MWA-6). This suggests that the majority of the customers  
12 served by Duke do not significantly value increased service reliability without regard  
13 to cost. In other words, price is a more important factor to customers than increased  
14 reliability.

15  
16 ***Q27. IS THERE OTHER EVIDENCE TO INDICATE THAT THE PRICE OF***  
17 ***ELECTRIC SERVICE IS MORE IMPORTANT TO DUKE'S CUSTOMERS***  
18 ***THAN INCREASED SERVICE RELIABILITY?***

19 ***A27.*** Yes. In the survey conducted by Duke included as Attachment MWA-4, the Utility  
20 asked its residential customers what they [REDACTED] and what they [REDACTED]  
21 Duke. For the latest quarter available, [REDACTED] percent of the respondents identified that

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1 what they [REDACTED] about Duke was [REDACTED] and [REDACTED] to [REDACTED]<sup>3</sup>

2 Only [REDACTED] percent responded what they [REDACTED] about Duke was [REDACTED]<sup>4</sup>

3 With respect to what customers [REDACTED] about Duke, [REDACTED] percent cited [REDACTED] and

4 [REDACTED] and only [REDACTED] percent cited [REDACTED] concerns.<sup>5</sup> From a

5 customer satisfaction perspective, these survey results indicate that Duke's proposal

6 to increase rates by \$104 million for increased service reliability is unwarranted.

7  
8 In addition, in Duke's last distribution base rate proceeding (Case No. 12-1682-EL-

9 AIR), members of the public presented their views on Duke's requested distribution

10 base rate increase of \$87 million. My review of the transcripts from the local public

11 hearings in those proceedings indicates that the public's overwhelming concern was

12 increasing rates, not service reliability.<sup>6</sup> The PUCO's Order in Duke's last

13 distribution base rate proceeding noted that most of the testimony received at the

14 local public hearings expressed a general opposition to any increase in Duke's rates.<sup>7</sup>

15 Despite customers' opposition to further rate increases under the Utility's proposal in

16 this case, customers would pay \$104 million over four years for increased service

17 reliability, without any assurance that service reliability will actually improve.

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<sup>3</sup> Attachment MWA-4 at 9.

<sup>4</sup> Attachment MWA-4 at 9.

<sup>5</sup> Id. at 10.

<sup>6</sup> Case No. 12-1685-EL-AIR, Local Public Hearing Transcripts for hearing held on February 19, 20, 25, and 28 (March 29, 2014).

<sup>7</sup> Id.

1 ***Q28. SHOULD RIDER DCI BE APPROVED BY THE PUCO?***

2 ***A28.*** No. Duke claims that Rider DCI is necessary to satisfy customer demands for  
3 increased service reliability. Yet Duke has failed to demonstrate that customers are  
4 willing to pay the additional costs necessary to fund the DCI for improvements in  
5 service reliability. Moreover, under the comprehensive distribution base rate setting  
6 process, customers are currently receiving increasingly reliable service. Therefore, it  
7 appears that Duke is already dedicating sufficient resources to the reliability of its  
8 distribution system. Duke has presented no analyses or studies to support its claim  
9 that current spending levels are not sufficient to maintain service reliability. Duke  
10 has not demonstrated that its proposed capital improvement programs are necessary  
11 to maintain service reliability.

12  
13 Even if these capital improvement programs were necessary, Duke has not  
14 demonstrated that the traditional base rate setting process is inadequate to allow it to  
15 collect the costs associated with these programs in the future. In addition, as just  
16 explained, the evidence indicates that customers are more concerned with price and  
17 avoiding rate increases than increased service reliability. Therefore, Duke's  
18 expectation that its customers want additional service reliability and are willing to pay  
19 for it is inconsistent with its customers' perception that service reliability is currently  
20 adequate and that customers do not want to see their rates increase in order to  
21 increase service reliability. Finally, as subsequently discussed, there are flaws with  
22 the mechanics of Rider DCI, which merit its rejection.

1 ***Q29. WHAT CONCERNS DO YOU HAVE WITH THE MECHANICS OF RIDER***  
2 ***DCI?***

3 ***A29.*** I have concerns with the use of projected data, the failure to recognize operation and  
4 maintenance (“O&M”) expense savings, the calculation of property taxes, and the  
5 inclusion of allocated common general plant.

6  
7 ***Q30. PLEASE EXPLAIN YOUR CONCERN RELATED TO THE USE OF***  
8 ***PROJECTED DATA.***

9 ***A30.*** Duke is proposing to set rates under Rider DCI based on projected costs. As such, the  
10 potential exists for Duke to recover through rates costs which it has not actually  
11 incurred. Duke has proposed no mechanism to reconcile projected and actual costs  
12 under Rider DCI. This could result in customers being charged for costs that Duke  
13 does not incur. If Rider DCI were to be approved by the PUCO, it should be based on  
14 actual costs.

15  
16 ***Q31. PLEASE EXPLAIN YOUR CONCERN WITH RIDER DCI AND O&M***  
17 ***EXPENSE SAVINGS.***

18 ***A31.*** The incremental investment that Duke is proposing to make if Rider DCI is approved  
19 will result in O&M expense savings. Duke is proposing to retain all of these savings  
20 until the Utility files its next base rate case, whenever that may be. At that time the  
21 O&M expense savings would be reflected in base rates.  
22 It is not reasonable or equitable for customers to pay for all of the costs associated  
23 with Duke’s incremental investment and not receive any of the benefits from the

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O&M savings between base rate cases. Duke's treatment of O&M expense savings is inconsistent with how O&M expense savings were treated under its natural gas Accelerated Mains Replacement Program ("AMRP").<sup>8</sup> It is my understanding that the AMRP program enabled Duke to accelerate the replacement of bare steel and cast iron distribution mains that potentially posed a safety and service reliability problem.<sup>9</sup> One of the customer benefits from the AMRP was that O&M cost savings were immediately credited to help reduce the cost of the AMRP on customers.<sup>10</sup> If Rider DCI is approved by the PUCO, I recommend that Duke be required to identify any O&M expense savings and that these savings be reflected as a credit to Rider DCI.

***Q32. PLEASE EXPLAIN YOUR CONCERN WITH RIDER DCI AND THE  
CALCULATION OF PROPERTY TAXES.***

***A32.*** Duke is assessed Tangible Personal Property ("TPP") and Real Property ("RP") taxes on its plant in service. For the TPP tax, when plant is placed in service, it is not assessed the TPP tax until the following year and the TPP tax would not be paid until the year after. For example, plant placed in service in 2015 will be assessed in the 2016 tax year and paid in 2017. For the RP tax, plant is assessed as of January 1<sup>st</sup> of each year, but is not billed until the following year. For example, plant assessed on

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<sup>8</sup> *In The Matter of The Application of The Cincinnati Gas & Electric Company for an Increase in Its Gas Rates in Its Service Territory*, Case No. 01-1228-GA-AIR, Opinion and Order (May 30 2001).

<sup>9</sup> *Id.*, Opinion and Order at 4 (May 30, 2002).

<sup>10</sup> *Id.*, Stipulation and Recommendation at 9, paragraph 6 (April 17, 2002).

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1 January 1, 2015 will not be paid until 2016, and any plant placed in service in 2015  
2 after January 1, 2015 would not require the payment of the RP tax until 2017.

3 Under Rider DCI, Duke would include the applicable property taxes in rates when  
4 plant is placed in service even though the property taxes would generally not be  
5 assessed until the following year. This is unreasonable and will cause customers to  
6 pay for costs not yet incurred by Duke or reflected on its books. If Rider DCI is  
7 approved by the PUCO, property taxes should not be included until the property  
8 being taxed is recognized as taxable by the applicable taxing authority.

9  
10 *Q33. PLEASE EXPLAIN YOUR CONCERN RELATED TO INCLUDING*  
11 *ALLOCATED COMMON GENERAL PLANT IN RIDER DCI.*

12 *A33.* Common general plant is allocated to Duke's electric distribution, electric  
13 transmission, unregulated electric generation, and gas distribution businesses on  
14 factors including the net plant in service of each of these businesses. With the  
15 proposed additional investment in electric distribution plant, the common general  
16 plant allocated to electric distribution service is likely to increase and the associated  
17 costs will be recovered under Rider DCI. This would occur even if Duke's total  
18 investment in common general plant did not increase. It would be unreasonable for  
19 Duke to increase rates to recover the costs associated with additional investment  
20 when no additional investment has been made. This would mean that customers  
21 would be paying for costs not actually incurred by Duke.

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1 I would also note that it is my understanding that while riders such as Rider DCI have  
2 been implemented under the PUCO authority to approve electric security plans,  
3 including provisions regarding distribution infrastructure and modernization  
4 incentives for the electric distribution utility, they have not included general plant.  
5 Common general plant, as the name implies, is plant that relates to the general  
6 operations of the utility and is not directly related to modernization. While it is true  
7 that general plant can support distribution operations, that plant, as the title implies,  
8 also supports other utility functions. Common general plant is not distribution  
9 infrastructure and does not relate to the modernization of that infrastructure. While  
10 additions to common general plant may indirectly lead to improved electric service  
11 reliability, such additions do not represent upgrades or modernization of distribution  
12 infrastructure. Therefore, if Rider DCI is approved by the PUCO, common general  
13 plant should be excluded.

14  
15 ***Q34. DO YOU HAVE ANY COMMENTS CONCERNING THE RATE OF RETURN***  
16 ***THAT CUSTOMERS WILL PAY ON THE INCREMENTAL INVESTMENT***  
17 ***UNDER RIDER DCI?***

18 ***A34.*** Yes. As previously indicated, the rate of return applied to the incremental investment  
19 would be that from Duke's most recently concluded distribution base rate case, and  
20 includes a 9.84 percent return on equity ("ROE"). OCC witness Matthew I. Kahal  
21 testifies that Rider DCI and subsequently discussed Rider DSR will reduce Duke's  
22 business risk. As a result he recommends a lower ROE for these Riders, if they are  
23 approved.

1 ***Q35. IF THE PUCO APPROVES RIDER DCI DESPITE YOUR CONCERNS,***  
2 ***PLEASE SUMMARIZE HOW SHOULD RIDER DCI BE MODIFIED?***

3 ***A35.*** If the PUCO approves Rider DCI despite my concerns, I recommend that actual  
4 rather than projected data be used to calculate Rider DCI, O&M expense savings  
5 should be reflected as a credit to Rider DCI, property taxes should not be included  
6 under Rider DCI until the property being taxed is recognized as taxable by the  
7 applicable taxing authority, common general plant should be excluded. And, the  
8 PUCO should explicitly reserve the right to evaluate the prudence of the costs  
9 recovered under Rider DCI at any time and disallow any costs not found to be  
10 prudent.

11  
12 **V. DISTRIBUTION STORM RIDER**

13  
14 ***Q36. PLEASE DESCRIBE DUKE'S PROPOSED RIDER DSR.***

15 ***A36.*** Duke's current distribution base rates include \$4.4 million per year for major storm  
16 O&M expense recovery. Duke is proposing to establish a regulatory asset account to  
17 defer the costs above or below this base rate amount in each calendar year. The  
18 Utility is proposing to recover the balance of this deferral in its next distribution base  
19 rate case unless the cumulative balance exceeds \$5 million at the end of a calendar  
20 year. Once the balance exceeds \$5 million, as either a regulatory debit or a regulatory  
21 credit, Duke will either collect or return to customers the balance in the regulatory  
22 account under Rider DSR.



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1 ***Q37. WILL CUSTOMERS BE CHARGED FOR CARRYING COSTS UNDER RIDER***  
2 ***DSR?***

3 ***A37.*** Yes. Any monthly positive or negative balance in this deferral account would accrue  
4 a carrying cost at the long-term cost of debt approved in Duke's most recently  
5 concluded distribution base rate case.

6  
7 ***Q38. WHY IS DUKE PROPOSING RIDER DSR?***

8 ***A38.*** Duke claims storm restoration costs are unpredictable and can be substantial, and  
9 Rider DSR will serve to mitigate excessive volatility in the Utility's earnings.

10  
11 ***Q39. HAS DUKE MADE ANY DEMONSTRATION THAT THE CURRENT BASE***  
12 ***RATE PROCEDURES HAVE CAUSED EXCESSIVE VOLATILITY IN ITS***  
13 ***EARNINGS OR THREATEN ITS FINANCIAL INTEGRITY?***

14 ***A39.*** No. I would also note that if a weather event causes the Utility to incur significant  
15 storm related restoration costs, filing a separate application with the PUCO to recover  
16 those costs would be reasonable. For example, in Case No. 09-1946-EL-RDR, Duke  
17 filed to recover \$30.7 million in costs it claims were caused by Hurricane Ike. I  
18 discuss this case in additional detail later in my testimony.

19  
20 ***Q40. WHAT ARE YOUR CONCERNS WITH RIDER DSR?***

21 ***A40.*** Initially, I am concerned that there will only be limited review of the costs to be  
22 collected under Rider DSR. That is, all interested parties will not likely have the  
23 opportunity to fully review the costs proposed to be collected from customers. A full

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1 review of costs collected from customers would be more likely to occur in a separate  
2 docketed proceeding or a base rate case. As a result, the potential to include  
3 ineligible or improper costs to be collected under Rider DSR will be greater. In  
4 addition, there will likely be limited review of the reasonableness of the costs  
5 proposed for recovery. This means that customers' rates may increase yet again with  
6 little oversight.

7  
8 ***Q41. IS THERE EVIDENCE TO VALIDATE YOUR CONCERNS?***

9 ***A41.*** Yes. In Case No. 09-1946-EL-RDR, Duke filed to recover \$30.7 million in storm  
10 restoration costs following the destruction caused by Hurricane Ike. The PUCO  
11 approved recovery of only \$14.1 million, finding that Duke:

- 12  
13 • Failed to show a reasonable basis for the recovery of \$3.2  
14 million in supplemental compensation paid to salaried  
15 employees;
- 16  
17 • Improperly proposed the recovery of \$371,796 in salaries  
already recovered in Duke's base rates;
- 18  
19 • Improperly proposed for recovery approximately \$2 million  
20 in supervision costs and labor loaders, e.g., items such as  
21 the cost of fringe benefits and payroll taxes associated with  
labor costs;
- 22  
23 • Failed to prove that all of the affiliate-related costs should  
24 be recoverable, resulting in a disallowance of  
approximately \$1.3 million in claimed costs; and
- 25  
26 • Failed to substantiate approximately \$10 million in  
contractor payments proposed for recovery.<sup>11</sup>

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<sup>11</sup> *In re Application of Duke Energy Ohio, Inc., 131 Ohio St. 3d 487, 2012-Ohio-1509.*

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1    ***Q42. SHOULD RIDER DSR BE APPROVED BY THE PUCO?***

2    *A42.* No, it should not. Duke has not demonstrated that the current base rate storm  
3       restoration cost recovery procedures are unreasonable or inadequate, and customers'  
4       rates should not increase without a thorough review of the reasonableness of the costs  
5       proposed for recovery.

6

7    ***Q43. DO YOU HAVE AN ALTERNATIVE RECOMMENDATION?***

8    *A43.* Yes, if the PUCO were to not follow my recommendation and approve the regulatory  
9       asset account, I recommend that the PUCO order Duke to file annually for a PUCO  
10      Staff audit detailing an accounting of all storm expenses within its storm deferral  
11      account, consistent with the process in other proceedings.<sup>12</sup> Prior to collecting or  
12      returning to customers storm restoration costs, Duke should be required to file a  
13      separate application with the PUCO for which Duke will bear the burden of proving  
14      that the costs were prudently incurred and reasonable. The PUCO Staff and  
15      interested parties should be permitted to conduct discovery and file comments within  
16      90 days after the application is docketed. If any objections are not resolved by the  
17      Utility, the PUCO should require that an evidentiary hearing be scheduled, with the  
18      opportunity to present testimony before the PUCO.

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<sup>12</sup> See *In re Application of Duke Energy Ohio, Inc.*, Case No. 09-1946-EL-ATA, Application (December 11, 2009) at 4, citing Case No. 08-709-EL-AIR; *In re Application of Columbus Southern Power Company and Ohio Power Company*, Case No. 11-346-EL-SSO, Opinion and Order (August 8, 2012), at 68-69.

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1    ***Q44. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?***

2    ***A44.*** Yes, it does. However, I reserve the right to incorporate new information that may  
3           subsequently become available. I also reserve the right to supplement my testimony  
4           in the event that the Utility, the PUCO Staff or other parties submit new or corrected  
5           information in connection with this proceeding.

## **CERTIFICATE OF SERVICE**

The undersigned hereby certifies that a true and correct copy of the foregoing *Direct Testimony of Jerome D. Mierzwa on Behalf of the Office of the Ohio Consumers' Counsel's, Public Version*, has been served upon the below-stated counsel by electronic transmission, this 26<sup>th</sup> day of September 2014.

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National Regulatory  
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## **How Should Regulators View Cost Trackers?**

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**September 2009**

**09–13**

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[http://www.nrri.org/pubs/gas/NRRI\\_cost\\_trackers\\_sept09-13.pdf](http://www.nrri.org/pubs/gas/NRRI_cost_trackers_sept09-13.pdf).

## **Executive Summary**

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

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

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

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

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



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## **How Should Regulators View Cost Trackers?**

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

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

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

### **I. The Definition and Mechanics of a Cost Tracker**

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

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<sup>1</sup> Regulators sometimes refer to cost trackers as "riders."

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

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

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

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

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

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<sup>3</sup> “Zero-based” refers to *all* the costs associated with a specific function, rather than just increments or decrements from test-year costs.

<sup>4</sup> These costs represent money owed by customers to a utility that the utility has determined to be uncollectible.

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

## **II. Principles for Cost Recovery**

### **A. “Reasonable opportunity” criterion**

State commissions have applied myriad criteria for utility cost recovery. Regulators are legally bound to allow utilities the opportunity to recover prudently incurred costs. Prudent costs reflect utility management that makes rational and well-informed decisions. The word “opportunity” can refer to the utility having a good chance of earning its authorized rate of return and is distinct from an entitlement.<sup>6</sup> “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.”<sup>7</sup> 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.<sup>8</sup> Controlling utility costs is a primary

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<sup>6</sup> 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.

<sup>7</sup> An exception also might include the costs associated with a major storm causing extensive damage to a utility’s infrastructure.

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

objective of regulators because it contributes to lower rates and reflects efficient utility management. Cost trackers can, in various ways, result in higher utility costs.<sup>9</sup> 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.<sup>10</sup> As economist and regulator Alfred Kahn once remarked:

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

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

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

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

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

Rational utility management, as a general rule, would exert minimal effort in controlling costs if it has no effect on the utility's profits.<sup>12</sup> 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.<sup>13</sup> The result is higher rates to utility customers. A utility with a FAC might postpone maintenance of a power plant even when it would cost less than the savings in fuel costs. The utility could not immediately (or even at any time) recover additional maintenance costs, while it could pass the higher fuel costs through the FAC.

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

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<sup>11</sup> Alfred E. Kahn, *Economics of Regulation*, Vol. 2 (New York: John Wiley & Sons, 1971), 48.

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

<sup>13</sup> In the example above, regulators could eliminate any perverse incentive by simply allowing a cost tracker for maintenance expenses.

<sup>14</sup> See, for example, the Baron and DeBontd studies cited in footnote 9.

Cost trackers also could motivate utilities to shift more of their costs to functions subject to trackers.<sup>15</sup> 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.<sup>16</sup>

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

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

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

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<sup>15</sup> 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.

<sup>16</sup> I thank Adam Pollock for this insight.

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

<sup>18</sup> I thank Joseph Rogers for this insight.

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

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

### III. Utilities' Perspective on Cost Trackers

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

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

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

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<sup>19</sup> 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](http://nrri.org/pubs/gas/Gas_Supply_Planning_and_Procurement_jun08-07.pdf).

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



(2) increasing cost-recovery certainty,<sup>21</sup> 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.<sup>22</sup> Overall, cost trackers lower a utility's financial risk by stabilizing its earnings and cash flow.

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

#### **IV. Regulatory Rationales for Cost Trackers**

##### **A. "Extraordinary circumstances"**

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

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

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

<sup>22</sup> 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.

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

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

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.<sup>25</sup> A utility should recover revenues in excess of its operating expenses to provide a “fair return” to investors. Businesses including utilities need to earn a profit to compensate investors for business, financial, and other risks.<sup>26</sup>

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.<sup>27</sup>

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<sup>24</sup> 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.

<sup>25</sup> 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).

<sup>26</sup> 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.<sup>26</sup> 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.

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

## **B. "Severe financial consequences"**

Historically, commissions have approved cost trackers to avoid the possibility of a utility suffering a serious financial problem because of cost increases unforeseen at the time of the last rate case.<sup>28</sup> 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.<sup>29</sup> Commissions implicitly impute a risk premium in the authorized rate of return, partially to account for the earnings volatility from fluctuations in costs or revenues from the test year. Trackers affect what is called "business risk." Business risk refers to the uncertainty linked to the operating cash flows of a business. Business risk is multi-dimensional, inclusive of sales, cost, and operating risks. In the Capital Asset Pricing Model (CAPM), for example, the lower the utility's expected earnings volatility, the lower the measure of the utility's risk relative to the market portfolio (i.e., "beta"). Because

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

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

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

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

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

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

### **C. An illustration: FACs and PGAs**

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

Until fuel costs started to fluctuate sharply in the 1970s, some energy utilities had to operate without the ability to adjust prices outside a rate case.<sup>32</sup> 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.<sup>33</sup>

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<sup>30</sup> 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.

<sup>31</sup> 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.

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

<sup>33</sup> Although most state commissions had authority to initiate proceedings to reduce rates, few chose to exercise it.

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

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

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

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

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

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

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

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

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

traditional ratemaking, where rates remain fixed between rate cases, ESM weakens regulatory lag and thereby reduces the incentive of a utility to control its costs between rate cases.<sup>36</sup> 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.<sup>37</sup>

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

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

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

<sup>36</sup> 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.

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

On net, the utility benefits and its customers immediately pay for the infrastructure costs without benefiting from the lower operating costs (at least until new rates reflect the lower costs). Such an outcome would violate any common meaning of “fairness” and seriously calls into question the merits of using a single-function tracker without readjusting rates for the effect on a utility’s other functional areas.<sup>38</sup> 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.<sup>39</sup> 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.<sup>40</sup>

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

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<sup>38</sup> 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.

<sup>39</sup> 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.

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

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

## VI. Putting It All Together

Cost trackers have both positive and negative features that regulators must evaluate.<sup>42</sup> 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.<sup>43</sup>

### A. The positive side of cost trackers

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

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

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<sup>41</sup> 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.

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

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

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



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

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.<sup>46</sup> A cost tracker in this instance also might cut down on the frequency of future rate cases. Regulators in the future might want to explore less traditional ways for utilities to recover their costs for new technologies with inherently high operational and financial uncertainties.

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

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

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

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<sup>45</sup> 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.

<sup>46</sup> 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?* NRRJ 08-12, November 2008, at [http://nrrj.org/pubs/electricity/nrrj\\_preapproval\\_commitments\\_08-12.pdf](http://nrrj.org/pubs/electricity/nrrj_preapproval_commitments_08-12.pdf).

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

Even then, the regulator should consider the adverse incentive effects and how he or she can compensate for this problem.<sup>47</sup> 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).<sup>48</sup>

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

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

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

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

## VII. Questions Regulators Should Ask

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

1. Does a cost-tracker proposal meet the regulatory test of acceptability? What minimum threshold should a regulator set for consideration of a cost tracker?
2. What special circumstances exist to warrant cost recovery outside of a rate case?
3. What evidence does a utility present showing that the absence of a tracker for a particular cost could place it in financial jeopardy?
4. In addition to cost trackers, what other cost-recovery mechanisms can regulators rely on to allow a utility to recover substantial unexpected costs between rate cases? What are the public-interest effects of these mechanisms relative to cost trackers?
5. What advantages does a cost tracker offer? What are its disadvantages?

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

6. How should regulators weigh the downsides of cost trackers relative to the upsides? How important are adverse incentive effects relative to the value of stabilizing a utility's rate of return?
7. How should a regulator account for the net-cost effects of a new investment (e.g., capital costs less savings in operating costs) for which the utility wants cost recovery through a tracker?
8. How would the accumulation of cost trackers for a utility motivate the utility to take risks and improve its overall cost performance?
9. If a cost tracker is justified, how can regulators structure it to mitigate potential problems such as weakened incentives for cost control?
10. What conditions should a regulator attach to the approval of a cost tracker?
  - a. Should it require the utility to report on its cost performance in functional areas directly and indirectly affected by the tracker?
  - b. Should the regulator also require that all costs recovered through trackers be subject to a thorough prudence review?
  - c. Should the regulator reduce the utility's return on equity to account for the lower risk resulting from the tracker?

**Duke Energy Ohio**  
**Case No. 14-841-EL-SSO, 14-842-EL-ATA**  
**OCC Seventh Set Interrogatories**  
**Date Received: July 18, 2014**

**OCC-INT-07-148**

**REQUEST:**

Please identify for each year since 2005, the values for CAIDI, SAIDI, and SAIFI. Please identify these values on the basis of excluding storms and on the basis of including storms.

**RESPONSE:**

Ohio Reliability Indices						
	Excluding MEDs (storms)			Including MEDs (storms)		
YEAR	CAIDI	SAIFI	SAIDI	CAIDI	SAIFI	SAIDI
2005	82.20	1.49	128.45	95.79	1.95	185.88
2006	87.80	1.48	150.88	101.29	2.80	202.84
2007	97.07	1.33	128.66	159.69	2.95	328.71
2008	98.91	1.32	136.23	917.48	2.74	1,418.98
2009	99.39	1.30	128.76	159.48	2.62	309.26
2010	140.85	1.18	132.88	418.78	1.41	188.88
2011	167.60	1.38	147.95	151.78	1.99	302.41
2012	105.38	1.08	131.78	286.71	1.85	489.18
2013	117.80	0.98	115.40	121.56	1.32	160.66

\*note: the indices do not take into account outages caused by transmission, per PUCO rules.

**PERSON RESPONSIBLE:** Marc W. Arnold



## Press Release

### J.D. Power Reports

#### Price and Billing/Payment are Primary Drivers of Increased Overall Customer Satisfaction with Electric Residential Utilities

#### Improved Communications During Long Outages Increases Satisfaction

**WESTLAKE VILLAGE, Calif.: 17 July 2013** — Despite ongoing severe weather across the United States resulting in longer outage periods per event, customer satisfaction with residential electric utilities has increased substantially from 2012 driven primarily by improvements in billing/payment, price and outage communications, according to the J.D. Power 2013 Electric Utility Residential Customer Satisfaction Study<sup>SM</sup> released today.

The study, now in its 15th year, measures customer satisfaction with electric utility companies by examining six factors: power quality and reliability; price; billing and payment; corporate citizenship; communications; and customer service.

Overall satisfaction among residential customers of electric utilities has increased substantially in 2013 to 639 (on a 1000-point scale), up 14 points from 2012. While performance in all factors improves in 2013, billing and payment satisfaction (719) increases by a notable 19 points, the largest increase among the six factors. Power quality and reliability, an important driver of customer satisfaction and the second-highest-scoring factor, has improved to 692 from 677 in 2012. Communications satisfaction increases for a third consecutive year, climbing to 585 in 2013 from 579 in 2012 and 575 in 2011. Satisfaction scores in price (551) and customer service (706) are the highest they have been in the past four years, with customer service increasing by 9 points from 2012.

#### KEY FINDINGS

- Overall customer satisfaction with residential electric utilities increases by 14 points year over year to 639.
- Satisfaction in the billing and payment factor (719) is the highest score among all six factors.
- Price satisfaction (551) and customer service (706) are the highest it has been in four years.

With severe weather events across the United States, longer outages were reported in 2012, yet, electric utilities have improved their outage communications before, during and after these events. Satisfaction increases when utilities proactively communicate outage information regularly and clearly via the channels customers prefer, including utility-initiated phone calls, emails, text messages and social media sites.

"In addition to improving outage communication, electric utilities have made great strides in improving customer perceptions regarding billing and payment," said Jeff Conklin, senior director of the energy practice at J.D. Power. "With such a dramatic increase in billing and payment satisfaction in the 2013 study, it's clear that the electric utilities have listened to the Voice of the Customer by providing them with many choices to receive and pay their bill and with improved information on their billing statements."

According to the study, satisfaction increases when customers are offered billing and payment options. Satisfaction among customers who select their own payment due date is 756, compared with 714 among those who do not select a due date. Satisfaction among customers who receive an electronic bill is 745,

compared with 709 among those who receive only a paper statement. Among customers who are on a fixed budget bill payment plan, satisfaction is 736, compared with 718 among those who are not on this plan. Billing and payment satisfaction increases by 54 points when billing statements include a consumption graph (740). Satisfaction is highest among customers who use their utility's online website to check their account or pay a bill (742), followed by auto-deductions from a bank account (736); recurring credit card payments (726); and through bank's online bill payment (717). The percentage of customers who mail their payment has decreased to 26 percent in 2013 from 29 percent in 2012, indicating that customers are using alternative payment options.

Price satisfaction improves substantially for a second consecutive year (+12 points), as customers indicate lower average bill amounts, down \$3 per month from 2012 to \$132. Price satisfaction is 101 points higher among customer who say they are "very familiar" with their utility's energy-saving programs than among those who say they are only "somewhat familiar."

Power quality and reliability (PQ&R) increases by 15 points in 2013, driven by a 19-point increase in the West region. The study finds that utilities have increased their number of communications with customers regarding lengthy outages in 2013. The most satisfying sources of outage information are emails from the utility (762 PQ&R); text messages from the utility (736); utility's social media site (724); calls from the utility (718); and customer emails sent to the utility (703).

#### **Study Rankings**

The Electric Utility Residential Customer Satisfaction Study ranks midsize and large utility companies in four geographic regions: East, Midwest, South and West. Companies in the midsize utility segment serve between 125,000 and 499,999 residential customers, while companies in the large utility segment serve 500,000 or more residential customers.

#### **East Region**

PPL Electric Utilities ranks highest among large utilities in the East region, followed by Central Maine Power; Duquesne Light; and West Penn Power, respectively.

Among midsize utilities in the East region, Southern Maryland Electric Cooperative ranks highest for a sixth consecutive year, followed by Penn Power; Delmarva Power; and Met-Ed, respectively.

#### **Midwest Region**

MidAmerican Energy ranks highest in the large utility segment in the Midwest region for a sixth consecutive year. We Energies; Alliant Energy; and Xcel Energy-Midwest follow, respectively.

Omaha Public Power District ranks highest in the midsize utility segment in the Midwest region for a sixth consecutive year and receives an award in the study for a 13th consecutive year. Following Omaha Public Power District in the segment rankings are Kentucky Utilities; Wisconsin Public Service; and Indianapolis Power & Light, respectively.

#### **South Region**

OG&E ranks highest in the large utility segment in the South region, followed by FPL; Georgia Power; and CPS Energy, respectively.

Sawnee EMC ranks highest in the midsize utility segment in the South region, followed by Jackson EMC; Clay Electric Cooperative; and NOVEC, respectively.

**West Region**

Salt River Project (SRP) ranks highest in the large utility segment in the West region for a sixth consecutive year and receives an award in the study for a 12th consecutive year. Following Salt River Project in the segment rankings are SMUD; Portland General Electric; and APS, respectively.

Clark Public Utilities ranks highest in the midsize utility segment in the West region for a sixth consecutive year, followed by Colorado Springs Utilities; Seattle City Light; and Snohomish County PUD, respectively.

**J.D. Power offers the following tips to consumers:**

- Customers should register their account online at their utility's website to get access to detailed account history.
- Customers who want to go paperless should sign up for e-bill statements from their utility.
- Many utilities now offer text or email notifications and alerts, such as reminders about usage toward a budgeted amount or outage updates.
- Some utilities now have smartphone apps that allow you to review and pay your bills or to report outages.

The 2013 Electric Utility Residential Customer Satisfaction Study is based on responses from 102,734 online interviews conducted from July 2012 through May 2013 among residential customers of the 126 largest electric utility brands across the United States, which collectively represent nearly 94 million households.

**About J.D. Power**

J.D. Power is a global marketing information services company providing performance improvement, social media and customer satisfaction insights and solutions. The company's quality and satisfaction measurements are based on responses from millions of consumers annually. Headquartered in Westlake Village, Calif., J.D. Power has offices in North/South America, Europe and Asia Pacific. For more information on car reviews and ratings, car insurance, health insurance, cell phone ratings, and more, please visit [JDPower.com](http://JDPower.com). J.D. Power is a business unit of McGraw Hill Financial.

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(Page 3 of 3)

Note: Eight charts follow.



**This foregoing document was electronically filed with the Public Utilities**

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**Case No(s). 14-0841-EL-SSO, 14-0842-EL-ATA**

Summary: Testimony Direct Testimony of Jerome D. Mierzwa, Public Version, on Behalf of the Office of the Ohio Consumers' Counsel electronically filed by Ms. Deb J. Bingham on behalf of Grady, Maureen R. Ms.