OCC EXHIBIT _______

BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of Ohio Edison Company, The Cleveland Electric Illuminating Company and The Toledo Edison Company for Authority to Provide for a Standard Service Offer Pursuant to R.C.4928.143 in the Form of an Electric Security Plan.	)))))))	Case No. 14-1297-EL-SSO

DIRECT TESTIMONY
OF
DAVID J. EFFRON

On Behalf of the
Office of the Ohio Consumers' Counsel
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December 22, 2014

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I. INTRODUCTION

Q1. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A1. My name is David J. Effron. My address is 12 Pond Path, North Hampton, New Hampshire, 03862.

Q2. WHAT IS YOUR PRESENT OCCUPATION?

A2. I am a consultant specializing in utility regulation.

Q3. PLEASE SUMMARIZE YOUR PROFESSIONAL EXPERIENCE.

A3. My professional career includes over thirty years as a regulatory consultant, two years as a supervisor of capital investment analysis and controls at Gulf & Western Industries, and two years at Touche Ross & Co. as a consultant and staff auditor. I am a Certified Public Accountant and I have served as an instructor in the business program at Western Connecticut State College.

Q4. WHAT EXPERIENCE DO YOU HAVE IN THE AREA OF UTILITY RATE SETTING PROCEEDINGS AND OTHER UTILITY MATTERS?

A4. I have analyzed numerous electric, gas, telephone, and water filings in different jurisdictions. In regard to those analyses, I have prepared testimony, assisted attorneys in case preparation, and provided assistance during settlement negotiations with various utility companies.

I have testified in over three hundred cases before regulatory utility commissions in Alabama, Colorado, Connecticut, Florida, Georgia, Illinois, Indiana, Kansas, Kentucky, Maine, Maryland, Massachusetts, Missouri, Nevada, New Jersey, New York, North Dakota, Ohio, Pennsylvania, Rhode Island, South Carolina, Texas, Vermont, Virginia, and Washington.

Q5. PLEASE DESCRIBE YOUR OTHER WORK EXPERIENCE.

A5. As a supervisor of capital investment analysis at Gulf & Western Industries, I was responsible for reports and analyses concerning capital spending programs, including project analysis, formulation of capital budgets, establishment of accounting procedures, monitoring capital spending, and administration of the leasing program. At Touche Ross & Co., I was an associate consultant in management services for one year, and a staff auditor for one year.

Q6. HAVE YOU EARNED ANY DISTINCTIONS AS A CERTIFIED PUBLIC ACCOUNTANT?

A6. Yes. I received the Gold Charles Waldo Haskins Memorial Award for the highest scores in the May 1974 certified public accounting examination in New York State.

Q7. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND.

A7. I have a Bachelor's degree in Economics (with distinction) from Dartmouth College and a Masters of Business Administration Degree from Columbia University.

II. PURPOSE OF TESTIMONY

Q8. ON WHOSE BEHALF ARE YOU TESTIFYING?

A8. I am testifying on behalf of the Office of the Ohio Consumers' Counsel ("OCC").

Q9. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A9. On August 4, 2014, Ohio Edison Company ("OE"), The Cleveland Electric Illuminating Company ("CEI"), and The Toledo Edison Company ("TE") (collectively, the "Utilities" or "FirstEnergy") filed an application with the Public Utilities Commission of Ohio ("PUCO" or "Commission") seeking approval of a new electric security plan ("the proposed ESP" or "ESP IV"). As part of this application, FirstEnergy proposed certain provisions regarding its distribution service, including continuation of the incremental tax provision presently in effect, authorization to continue the Delivery Capital Recovery Rider ("Rider DCR") presently in effect, and implementation of a new Government Directives Rider ("Rider GDR") to recover incurred costs related to governmental directives. My testimony addresses the Utilities' proposals regarding the incremental tax provision, Rider DCR, and the implementation of the new Rider GDR.

Q10. DOES YOUR TESTIMONY ON THE UTILITIES' PROPOSALS REGARDING ITS DISTRIBUTION RIDERS MEAN THAT YOU AGREE THAT THE NUMEROUS RIDERS PRESENTLY IN EFFECT FOR FIRSTENERGY SHOULD BE APPROVED BY THE PUCO?

A10. 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 traditional base rate cases, where all elements of the cost of service are examined. As a general matter, riders entailing the automatic collection of certain utility costs from customers are contrary to sound ratemaking practice. When utilities are permitted to collect costs from customers through a rider, the incentive for a utility to control costs tends to be reduced or eliminated. Even worse, a rider can potentially incent a utility to make uneconomic choices. To the extent that such riders are approved, they should be limited to costs that are large, volatile, and outside of the utility's control. Examples of such costs could be purchased gas costs for a gas distribution utility or fuel and purchased power for an integrated electric utility.

FirstEnergy has presented little evidence in this proceeding that the costs that it is seeking to collect through its proposed riders meet these criteria (costs that are large, volatile, and outside of the utility's control). Additionally, FirstEnergy has not shown that its financial integrity would be somehow compromised if those costs could be collected only through a traditional base rate case where the costs would be subject to closer scrutiny. (As I explain later in this testimony, Rider DCR in particular appears to allow the Utilities to collect revenues that would not be collected under traditional utility ratemaking methods.) A report by the National Regulatory Research Institute ("NRRI") titled "How Should Regulators View Cost Trackers?" (September 2009) presents a succinct and balanced description of regulatory issues associated with riders, and I have attached a copy of this report to my testimony (DJE - Attachment 1).

Q11. HOW CAN RIDERS POTENTIALLY RESULT IN UNECONOMIC INCENTIVES TO A REGULATED UTILITY?

A11. Suppose that a regulated utility was faced with a decision between either replacing a piece of equipment or contracting to maintain the equipment. From a present value perspective it might be more economic to incur the cost to maintain the equipment rather than replace it. However, if the utility has a rider where it can automatically recover the cost of plant additions but would have to "absorb" any incremental maintenance expense under its existing base rates, then there is obviously an incentive to make the replacement even though that might not be the more economic option. Further, if a utility has a rider where it can automatically recover the cost of plant additions but would have to absorb any incremental maintenance expense, then there can even be an additional incentive to modify its accounting policies to capitalize those incremental maintenance costs that would otherwise be charged to expense.

Q12. ARE THERE ANY OTHER POTENTIAL PROBLEMS WITH COLLECTION OF COSTS FROM CUSTOMERS THROUGH RIDERS?

A12. Yes. The collection of costs from customers through riders can lead to increases in rates and revenues (collected by the utility) even when a regulated utility company does not have a revenue deficiency. As I explain later, this matter is of particular concern with regard to each of the FirstEnergy companies.

By contrast, in the absence of riders, a regulated utility would be able to implement rate increases only after a traditional rate case where all costs and the revenues under the rates in effect were taken into consideration. If it was determined that the rates in effect were already producing an adequate return, then no rate increase would be authorized.

III. INCREMENTAL TAX PROVISION

Q13. PLEASE DESCRIBE THE INCREMENTAL TAX PROVISION IN THE UTILITIES' CURRENT ESP.

A13. The incremental tax provision was approved by Commission in the Case No. 12-1230-EL-SS0[1] ("ESP III"). It allows the Utilities to apply for recovery of any new or incremental taxes going into effect subsequent to June 1, 2011, and not

[1] *In the Matter of Ohio Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company*, Case No. 12-1230-EL-SSO, Opinion and Order at 15, 57.

recovered elsewhere. The application is deemed to be approved if the Commission does not rule otherwise within ninety days.

Q14. IF THE INCREMENTAL TAX PROVISION REMAINS IN EFFECT FOR ESP IV, SHOULD THERE BE CERTAIN MODIFICATIONS?

A14. Yes. There should be two modifications: (1) The provision should be symmetrical – that is, it should apply to changes that reduce taxes as well as to changes that increase taxes; and (2) the provision should be subject to a materiality threshold – that is, it should not apply to tax changes that do not have a substantial effect on the Utilities' expenses.

Q15. WHY SHOULD THE INCREMENTAL TAX PROVISION BE SYMMETRICAL?

A15. It is only reasonable that if the Utilities can recover incremental expenses related to new taxes or incremental taxes, then they should also credit customers for any reductions to expenses related to the elimination of taxes or decreases in taxes. Therefore, if any taxes presently in effect are eliminated or decreased, the Utilities should be required to notify the Commission and the parties to this proceeding of such changes, and to implement a rate mechanism to credit customers for such changes, subject to the materiality threshold addressed below.

Q16. WHY SHOULD THE INCREMENTAL TAX PROVISION BE SUBJECT TO A MATERIALITY THRESHOLD?

A16. There is no reason why the Utilities should be able to modify their rates for tax changes that have a relatively immaterial effect on their expenses and income. If the effect is not substantial, then no adjustment to the rates for utility service is necessary. The Utilities should not go through the process of application, tariff modification, and customer notification for tax changes that do not have a material effect on expenses. In addition, the smaller the effect of the tax change, the less the chance that it will actually cause the Utilities to experience a revenue deficiency (or excess). Therefore, implementation of any collection of or credit for tax rate changes should be subject to a materiality threshold.

Q17. WHAT DO YOU RECOMMEND AS MATERIALITY THRESHOLDS FOR EACH OF THE UTILITIES?

A17. I recommend that unless the annual effect of any tax change is greater than $3 million for OE, $2 million for CEI, or $1 million for TE, the tax change should not be subject to recovery from or credit to customers through the incremental tax provision. These amounts are equal to approximately one percent of the 2013 pre-tax operating income for each of the FirstEnergy Utilities.

IV. DELIVERY CAPITAL RECOVERY RIDER

Q18. PLEASE DESCRIBE RIDER DCR THAT CUSTOMERS PAY NOW AS PART OF THEIR ELECTRIC SERVICE.

A18. The PUCO approved Rider DCR (that customers presently pay) as part of the Utilities' ESP II in Case No. 10-338-EL-SSO.[2] The purpose of Rider DCR is to collect from customers the incremental revenue requirement associated with increases in net utility plant since May 31, 2007 (the date certain in Case No. 07-551-EL-AIR, the Utilities' most recent base distribution rate case at the time of the implementation of Rider DCR). Rider DCR was extended through May 31, 2016 in Case No. 12-1230-EL-AIR ("ESP III").[3]

Q19. WHAT ARE THE COMPONENTS OF THE RIDER DCR REVENUE REQUIREMENT?

A19. There are three components of the revenue requirement for Rider DCR. The first component is the return on the increase in net rate base from Case No. 07-551-EL-AIR, defined as the increase in gross distribution plant in service, less the increase in related accumulated depreciation and accumulated deferred income taxes. The second component is the depreciation on additions to distribution plant in service. The third component is the property taxes on the additions to distribution plant in

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[2] *In the Matter of Ohio Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company*, Case No. 11-338-EL-SSO, Opinion and Order at 11-12, 35-36,40 (August 25, 2010).

[3] *In the Matter of Ohio Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company*, Case No. 12-1230-EL-SSO, Opinion and Order at 10-11, 33-34 (July 18, 2012).

service. As proposed by the Utilities, the planned annual aggregate Rider DCR revenue caps would be $240 million for the period June 1, 2016 through May 31, 2017, $270 million for the period June 1, 2017 through May 31, 2018, and $300 million annually for the period June 1, 2018 through the end of ESP IV, with the individual utility revenue caps set at the following percentages of the aggregate revenue caps: OE-50 percent, CEI-70 percent, and TE-30 percent. (For example, for the last period of the proposed DCR, revenues for OE could not exceed $150 million, for CEI $210 million, or for TE $90 million, but the revenues for all three together in the aggregate could not exceed $300 million.)

Q20. SHOULD THE PUCO AUTHORIZE RIDER DCR TO CONTINUE TO OPERATE AS IT HAS IN ESP II AND ESP III WITHOUT FURTHER JUSTIFICATION BY THE UTILITIES?

A20. No. As I noted above, one potential problem with riders is that they can lead to increases in utility rates and revenues even when a regulated utility company does not have a revenue deficiency. Based on my analysis, this is more than just a potential problem with each of the FirstEnergy utilities.

Q21. PLEASE EXPLAIN.

A21. My Schedule DJE-1 is an analysis of the returns by each of the FirstEnergy distribution utilities on their investments in utility operations in 2013. Although I am not a rate of return expert, my calculations show that each of the Utilities earned returns in 2013 well in excess of what could reasonably be considered an adequate return, based on returns authorized by the PUCO, as well as other utility commissions, in recent years. The purpose of Rider DCR should be to allow the Utilities to avoid revenue deficiencies resulting from additions to utility plant in service, not to perpetuate or augment excess earnings. Therefore, if the Utilities are earning returns in excess of their actual costs of capital, additional DCR increases are unnecessary and inappropriate.

Q22. PLEASE SUMMARIZE THE ANALYSIS ON YOUR SCHEDULE DJE-1.

A22. On Schedule DJE-1, I have calculated the earned return on rate base and earned return on equity in 2013 for each of the Utilities based on the utility operating income stated on a ratemaking basis, the Utilities' net rate base investments, and the common equity supporting those rate bases.

Q23. HOW DID YOU CALCULATE THE UTILITY OPERATING INCOME TO BE USED IN YOUR CALCULATION OF THE EARNED RETURN ON RATE BASE?

A23. My analysis begins with the actual 2013 utility operating income as reported in the 2013 FERC Form 1 for each of the Utilities. I have then made certain adjustments to the utility operating income for the purpose of calculating the earned return on investment in utility operations.

The first adjustment is to eliminate the effect on income taxes of interest deductions for interest on debt that does not support the rate bases. As I explain below, each of the Utilities' balance sheets include substantial balances of non-utility assets that are not included in their rate bases. The tax deductions for interest on debt not supporting the rates bases should be eliminated from the calculation of the income tax expense included in utility operating expenses for the purpose of calculating the earned return on the utility rate base.

The purpose of the second adjustment is to eliminate the effect of items that I have assumed for the purpose of this analysis would not normally be reflected in the determination of utility operating expenses for ratemaking purposes. I used the "Special / Extraordinary Items After-Tax" adjustment from the Utilities' 2013 Significantly Excessive Earnings Test ("SEET") for this item.[4] I am not aware of the details of the "Special / Extraordinary Items After-Tax" adjustment in the Utilities' 2013 SEET. However, it is my understanding that this item represents "portions of … net income [that] are special, extraordinary or nonrecurring, or are otherwise non-representative of the utility's operations."[5] Based on this description, the "Special / Extraordinary Items After-Tax" item in the SEET calculation appears to represent the type of adjustments that would be made in the determination of the revenue requirement in a rate case.

[4] *In the Matter of the Determination of the Existence of Significantly Excessive Earnings for 2013 Under the Electric Security Plan of Ohio Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company*, Case No. 14-828-EL-UNC.

[5] See, for example, Docket No. 14-0828-EL-UNC, Direct Testimony of K. Jon Taylor, page 8.

The result after these two adjustments is the adjusted utility operating income that I use to calculate the earned return on rate base.

Q24. HOW DID YOU CALCULATE THE RATE BASES OF EACH OF THE UTILITIES?

A24. The major components of rate base are plant in service, accumulated depreciation, and accumulated deferred income taxes ("ADIT"). I took these items from the Utilities' November 1, 2013 Rider DCR filing in Case No. 13-2005-EL-RDR. The plant in service, accumulated depreciation, and ADIT are the balances as of September 30, 2013. Based on my review of the PUCO Staff workpapers supporting the PUCO Opinion & Order in Case No. 07-551-EL-AIR and each 2013 FERC Form 1, the most significant other component of rate base is the deferred charge related to the Rate Certainty Plan deferrals. I have added this item to rate base for each of the utilities.

Q25. WHAT RETURN ON RATE BASE HAVE YOU CALCULATED FOR EACH OF THE UTILITIES?

A25. I have calculated an earned return on rate base of 11.2 percent for OE, 11.7 percent for CEI, and 10.7 percent for TE. By comparison, the authorized return on rate base in Case No. 07-551-EL-AIR was 8.48 percent.

Q26. HAVE YOU ALSO CALCULATED THE RETURN ON COMMON EQUITY SUPPORTING RATE BASE THAT THESE RETURNS ON RATE BASE IMPLY?

A26. Yes. To calculate the return on equity ("ROE"), I have begun with the adjusted utility operating income for each of the utilities, as described above. I then subtracted the interest expense on debt supporting rate base, which I calculated by multiplying the weighted cost of debt (as shown in Utilities' November 1, 2013 DCR filing in Case No. 13-2005-EL-RDR) by the rate base. This method of calculating interest expense excludes interest on debt supporting non-rate base assets. As noted above, I also adjusted income taxes to exclude the benefits of the tax deductions related to the interest on debt supporting non-rate base assets.

I have calculated an earned return on equity of 16.0 percent for OE, 17.1 percent for CEI, and 15.1 percent for TE. By comparison, the authorized return on equity in Case No. 07-551-EL-AIR was 10.50 percent.

Q27. WHY DOES YOUR CALCULATION OF THE EARNED RETURN ON EQUITY DIFFER SO GREATLY FROM THE RETURN ON EQUITY IN THE UTILITIES' FINANCIAL STATEMENTS AND THE RESULTS OF THE UTILITIES'' CALCULATIONS OF THE ROE FOR SEET PURPOSES IN CASE NO.14-828-EL-UNC?

A27. My calculation of the ROE here reflects the returns earned on the investment in utility operations. This is the relevant ROE for the purpose of determining whether the Utilities' present distribution rates are producing excess revenues.

The ROE based on the financial statements and the Utilities' calculation of the ROE for the purpose of the SEET do not measure the return earned on common equity supporting the Utilities' respective rate bases. That is, they do not measure the earned ROE on a ratemaking basis.

The balance sheets of each of the FirstEnergy Utilities include significant non-rate base assets. In the case of CEI and TE, the largest non-rate base asset is purchase goodwill, with a balance of approximately $1.6 billion for CEI and $500 million for TE. To put those balances of goodwill in perspective, they are actually greater than the rate bases of the respective companies. OE's non-rate base assets in comparison to its rate base are not so as large as those of CEI and TE but are still substantial.

The SEET does not eliminate the common equity supporting the non-rate base assets from common equity (the denominator) in the ROE calculation, and it does not eliminate the interest on debt supporting the non-rate base assets from expenses for the purpose determining net income (the numerator) in the ROE calculation. Because it does not distinguish between rate base assets and the substantial non-rate base assets, the SEET is going to derive a lower ROE than the actual ROE earned on the investment in utility operations, and in the case of CEI and TE, much lower.

Q28. CAN YOU BRIEFLY EXPLAIN WHAT THE GOODWILL REPRESENTS AND WHY YOU DESCRIBE IT AS A NON-RATE BASE ASSET?

A28. Yes. Goodwill, also referred to as an acquisition premium, represents the excess of the purchase price over the net book value of the assets being acquired when one company is acquired by, or merged into, another company. Depending on the circumstances, the goodwill may be "pushed down" to the acquired company and appear on the books of that company.

Goodwill in the case of a corporate acquisition or merger is the result of a transfer of wealth from one group of shareholders to another group of shareholders. The price being paid in excess of net book value of the shares acquired is a matter between the shareholders of the two companies involved in the merger, and should not be the responsibility of ratepayers. As a general rule, goodwill is excluded from rate base and from the determination of utility revenue requirements, as purchase goodwill does not represent an investment in assets used to provide utility service to customers.

Q29. HAVE YOU CALCULATED WHAT THE EXCESS REVENUES OF THE UTILITIES WOULD BE BASED ON YOUR CALCULATED ROE'S AND THE PRESENTLY AUTHORIZED RETURN ON EQUITY?

A29. Yes. The return on equity in Case No. 07-551-EL-AIR was 10.50 percent. Based on that authorized ROE and the ROE's that I have calculated, OE has excess revenues of $58.9 million annually, CEI has excess revenues of $60.6 million annually, and TE has excess revenues of $15.6 million annually.

Q30. HAVE YOU CALCULATED WHAT THE EXCESS REVENUES OF THE UTILITIES WOULD BE BASED ON DR. WOOLRIDGE'S RATE OF RETURN RECOMMENDATIONS?

A30. Yes. With regard to the return on equity, Dr. Woolridge concludes that the appropriate equity cost rate for OE, CEI, and TE is 8.7%. With an authorized return on equity of 8.7% and the capital structure and cost of debt from Case No. 07-551-EL-AIR, the excess revenues would be $78.0 million for OE, $77.1 million for CEI, and $21.6 million for TE annually (Schedule DJE-1).

Dr. Woolridge also proposes a capital structure consisting of 55% long-term debt and 45% common equity, with a long-term debt cost rate of 4.54%. This results in an overall fair rate of return, or cost of capital, of 6.41%. With Dr.

Woolridge's capital structure, cost of long-term debt, and 8.7% return on equity, the excess revenues are $97.2 million for OE, $93.5 million for CEI, and $27.7 million for TE annually (Schedule DJE-2).

Q31. DOES YOUR ANALYSIS PROVE CONCLUSIVELY THAT THE UTILITIES HAVE EXCESS REVENUES OF THESE MAGNITUDES?

A31. No. This would require a full determination of the rate base and net operating income adjusted to reflect all appropriate ratemaking adjustments for each of the Utilities, as would be done in a traditional rate case. The results of such a determination could be lower revenue excesses or higher revenue excesses. However, given the magnitude of the differences between the earned ROE's and the presently authorized ROE, I believe that the analysis on Schedule DJE-1 strongly implies that the Utilities have excess revenues.

Q32. HOW DOES THIS RELATE TO THE OPERATION OF RIDER DCR?

A32. Rider DCR is intended to compensate the Utilities for the costs of additions to plant in service over and above the plant included in their rate bases in the most recent rate cases. In effect, Rider DCR stands in place of rate cases that would allow the Utilities to adjust their rates for additions to plant in service (as well as other changes in their revenue requirements). That is, instead of having to file frequent rate cases to adjust rates for additions to plant in service, the Utilities periodically adjust their Rider DCR rates. However, Rider DCR should not operate to increase the Utilities' rates above what they would be if they actually did file rate cases to capture the costs of additions to plant in service. If the Utilities are already earning a return in excess of their cost of capital, implementing DCR increases would only serve to perpetuate, or even to increase, the excess return on the investment in rate base used to provide service to customers.

Q33. WHAT DO YOU RECOMMEND?

A33. Prior to the implementation of any further rate increases pursuant to Rider DCR, the PUCO should require the Utilities to file rate cases to establish the appropriate baseline against which any rate changes pursuant to Rider DCR should be measured. The rate cases would also establish the extent to which the Utilities are (or are not) presently earning returns in excess of their actual cost of capital. The Utilities should not be authorized to implement any further rate increases under Rider DCR until it is established that the effect of such rate increases would not serve to perpetuate or augment excess earnings.

Q34. IF THE PUCO DOES AUTHORIZE IMPLEMENTATION OF RIDER DCR, SHOULD THERE BE CERTAIN MODIFICATIONS TO THE MECHANISM PROPOSED BY FIRSTENERGY?

A34. Yes. There should be an investigation of whether changes in the following areas would be appropriate:

- It is not clear whether the calculation of the rate base used in the Rider DCR revenue requirement determination includes the effect of changes in the accrued Asset Removal Cost in FERC Account 254 or Account 230 since May 31, 2007. The Utilities declined to provide this information in response to OCC Interrogatory 5-126. (DJE-Attachment 2). The treatment of this item could affect the accumulated depreciation that is deducted from plant in service in the determination of rate base. The Utilities should be required to describe their treatment of this item. If it is determined that the Utilities' present treatment is not appropriate, it should be modified.

- It is not clear whether the calculation of the rate base used in the Rider DCR revenue requirement determination takes account of changes in the "FAS 109 Adjustment" included in FERC Account 190 and/or Account 283 since May 31, 2007. The Utilities declined to provide this information in response to OCC Interrogatory 5-127 (DJE-Attachment 2). The treatment of this item could affect the balance of Accumulated Deferred Income Taxes ("ADIT") that is deducted from plant in service in the determination of rate base. The Utilities should be required to describe their treatment of this item. If it is determined that the Utilities' present treatment is not appropriate, it should be modified.

- It is not clear whether the calculation of the rate base used in the Rider DCR revenue requirement determination takes account of changes in the "Customer Receivables for Future Income Tax" included in FERC Account 182 net of the "Customer Receivables for Future Income Tax" included in FERC Accounts 254 and/or 283. The Utilities declined to provide this information in response to OCC Interrogatory 5-128 (DJE-Attachment 2). The treatment of this item could affect the balance of ADIT that is deducted from plant in service in the determination of rate base. The Utilities should be required to describe their treatment of this item. If it is determined that the Utilities' present treatment is not appropriate, it should be modified.

- The Utilities should be required to document the balances of ADIT deducted from plant in service in the determination of the current rate base, and to reconcile and explain any differences between those balances and the balances in FERC Account 282, property related ADIT, as of the relevant date.

- From time to time regulated public utilities change their policies for capitalizing or expensing given types of expenditures. The timing of such changes in accounting policies can be problematic if the changes are made between rate cases. For example, a given type of expenditure may be treated as maintenance expense during a twelve-month period that serves as a test year in a rate case. The utility would then recover that cost as an annual expense in its revenue requirement. If at some point after the conclusion of the rate case, the utility were to change its accounting practices so that those costs were capitalized, then they would also be included in plant in service that goes into the rate base. This would result in a double recovery of those costs. Therefore, any changes in accounting policy that affect the capitalization of expenditures should be subject to PUCO approval. Any changes in the Utilities' capitalization policies should then be synchronized with the ratemaking treatment, so that the relevant expenditures will not be capitalized and included in the rate base used in the calculation of the Rider DCR revenue requirement at the same time that they are being recovered from customers in rates as current expenses.

V. GOVERNMENT DIRECTIVES RIDER

Q35. PLEASE DESCRIBE THE GOVERNMENT DIRECTIVES RIDER THAT THE UTILITIES ARE SEEKING TO IMPLEMENT.

A35. The proposed Government Directives Recovery Rider ("Rider GDR") would permit recovery of future costs related to programs required by legislative or governmental directives. The Utilities would seek authority from the Commission to defer and recover costs associated with government directives prior to including such costs for recovery in Rider GDR.

Q36. SHOULD THE COMMISSION AUTHORIZE IMPLEMENTATION OF RIDER GDR?

A36. No. If the Utilities believe that programs required by legislative or governmental directives would increase costs and cause a revenue deficiency, then the Utilities should file a rate case to recover the costs related to the directives. But the Utilities should not be able to recover the costs associated with the legislative or governmental directives absent a showing that any such costs actually cause revenue deficiencies.

Q37. IF THE COMMISSION DOES AUTHORIZE IMPLEMENTATION OF RIDER GDR, SHOULD THERE BE CERTAIN MODIFICATIONS TO THE RIDER AS PROPOSED BY THE UTILITIES?

A37. Yes. There should be three modifications: (1) The operation of the rider should be symmetrical; (2) the implementation of the rider should be subject to a materiality threshold; and (3) in addition to seeking authority to defer and recover the costs associated with each separate directive, the Utilities should be required to treat each directive as a discrete component of the GDR, and to track the costs, revenue requirement, and recovery of each component separately.

Q38. WHY SHOULD THE RIDER BE SYMMETRICAL?

A38. Again, it is only reasonable that if the Utilities can recover incremental expenses related to legislative or governmental directives, then they should also credit customers for any expense reductions resulting from legislative or governmental directives that have the effect of eliminating or reducing costs that are presently being incurred. Therefore, if any costs presently being incurred are reduced or eliminated as a result of legislative or governmental directives, the Utilities should be required to notify the Commission and the parties to this proceeding of such changes, and to implement a rate mechanism to credit customers for such changes, subject to the materiality threshold addressed below.

Q39. WHY SHOULD THE RIDER BE SUBJECT TO A MATERIALITY THRESHOLD?

A39. The Utilities should not modify their rates for legislative or governmental directives that have a relatively immaterial effect on their expenses and income**.** If the effect of legislative or governmental directives on costs is immaterial, then no adjustment to rates is necessary. Therefore, implementation of any collection of or credit for legislative or governmental directives should be subject to a materiality threshold.

Q40. WHAT DO YOU RECOMMEND AS MATERIALITY THRESHOLDS FOR EACH OF THE UTILITIES?

A40. Again, I recommend that unless the annual effect of any legislative or governmental directives is greater than $3 million for OE, $2 million for CEI, or $1 million for TE (which are equal to approximately one percent of the 2013 pre-tax operating income for each of the FirstEnergy Utilities), the effect of the legislative or governmental directives should not be subject to recovery from or credit to customers through the Government Directives Rider.

Q41. WHY SHOULD THE UTILITIES BE REQUIRED TO TRACK THE COSTS, REVENUE REQUIREMENT, AND RECOVERY OF EACH DIRECTIVE SEPARATELY?

A41. Treatment of each directive as a distinct component of the GDR would facilitate examination of the costs associated with directives, the recoverability of the costs, and the recovery of such costs. The types of expenditures covered by the GDR would have differing levels of complexity, duration, and potential disagreement regarding the recoverability of the relevant costs. Therefore, each directive should be accounted for separately from the other directives covered by the GDR.

VI. CONCLUSION

Q42. PLEASE SUMMARIZE YOUR TESTIMONY.

A42. There should be two modifications to the incremental tax provision: (1) The provision should be symmetrical, and (2) the provision should be subject to a materiality threshold.

If the PUCO determines that Rider DCR should continue in effect, then prior to the implementation of any further DCR rate increases, the Utilities should be required to file rate cases to establish the appropriate baseline against which any rate changes pursuant to Rider DCR can be measured. The Utilities should not be authorized to implement any further rate increases under Rider DCR until it is established that the effect of such rate increases would not serve to perpetuate or augment excess earnings.

The PUCO should not approve the implementation of Rider GDR. However, if Rider GDR is implemented, then there should be three modifications to the rider as proposed by the Utilities: (1) The rider should be symmetrical, (2) the rider should be subject to a materiality threshold, and (3) each directive should be treated as a separate component of the GDR and tracked separately.

Q43. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A43. Yes. However, I reserve the right to incorporate new information that may subsequently become available.

CERTIFICATE OF SERVICE

It is hereby certified that a true copy of the foregoing *Direct Testimony of David J. Effron on Behalf of the Office of the Ohio Consumers' Counsel* was served via electronic transmission this 22nd day of December 2014.

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FIRSTENERGY CORPORATION OHIO
EARNED RETURN ANALYSIS - 2013
($MILLION)

		OE	CEI	TE
Net Utility Operating Income	(A)	$ 210.6	$ 188.6	$ 67.3
Interest Synchronization Adjustment	(B)	(11.3)	(26.4)	(8.7)
Adjustment for Special/Extraordinary Items	(C)	(41.6)	(20.0)	(10.6)
Adjusted Utility Operating Income		$ 157.7	$ 142.2	$ 48.0
Rate Base as of 9/30/2013:				
Gross Plant	(D)	$2,962.5	$ 2,701.2	$1,075.1
Accumulated Depreciation	(D)	(1,136.5)	(1,078.0)	(511.6)
Net Plant		1,826.0	1,623.2	563.5
Accumulated Deferred Income Taxes	(D)	(477.6)	(450.4)	(141.8)
Other (Net Deferred Charges)	(E)	60.1	39.1	24.9
Net Rate Base		$1,408.5	$ 1,211.9	$ 446.6
Return on Rate Base		11.2%	11.7%	10.7%
Adjusted Utility Operating Income		$ 157.7	$ 142.2	$ 48.0
Interest on Debt Supporting Rate Base	(F)	47.0	40.4	14.9
Net Income		$ 110.7	$ 101.8	$ 33.1
Common Equity Supporting Rate Base	(G)	$ 690.1	$ 593.8	$ 218.8
Return on Equity Supporting Rate Base		16.0%	17.1%	15.1%
Excess Revenue Based on ROE of 10.50%	(D)	$ 58.9	$ 60.6	$ 15.6
Excess Revenue Based on ROE of 8.70%	(H)	$ 78.0	$ 77.1	$ 21.6

Sources:

(A) 2013 FERC Form 1, Page 114
(B) Case No. 13-2005-EL-RDR, 11/1/2013; 2013 FERC Form 1, Page 117
(C) Case No. 14-0828-EL-UNC, Schedule KJT-2
(D) Case No. 13-2005-EL-RDR, 11/1/2013
(E) 2013 FERC Form 1, Page 232: RCP Deferrals Net of Taxes
(F) Case No. 13-2005-EL-RDR, 11/1/2013 0.51*0.0654*Rate Base
(G) Case No. 13-2005-EL-RDR, 11/1/2013 0.49*Rate Base
(H) Testimony of Dr. Woolridge

FIRSTENERGY CORPORATION OHIO
EXCESS REVENUE BASED ON OCC RATE OF RETURN
($MILLION)

		OE	CEI	TE
Net Utility Operating Income	(A)	$ 210.6	$ 188.6	$ 67.3
Interest Synchronization Adjustment	(B)	(15.5)	(30.1)	(10.0)
Adjustment for Special/Extraordinary Items	(C)	(41.6)	(20.0)	(10.6)
Adjusted Utility Operating Income		$ 153.5	$ 138.5	$ 46.7
Rate Base as of 9/30/2013:				
Gross Plant	(D)	$ 2,962.5	$ 2,701.2	$ 1,075.1
Accumulated Depreciation	(D)	(1,136.5)	(1,078.0)	(511.6)
Net Plant		1,826.0	1,623.2	563.5
Accumulated Deferred Income Taxes	(D)	(477.6)	(450.4)	(141.8)
Other (Net Deferred Charges)	(E)	60.1	39.1	24.9
Net Rate Base		$ 1,408.5	$ 1,211.9	$ 446.6
Return on Rate Base		10.9%	11.4%	10.4%
Adjusted Utility Operating Income		$ 153.5	$ 138.5	$ 46.7
Interest on Debt Supporting Rate Base	(F)	35.2	30.3	11.2
Net Income		$ 118.3	$ 108.2	$ 35.5
Common Equity Supporting Rate Base	(G)	$ 633.8	$ 545.3	$ 201.0
Return on Equity Supporting Rate Base		18.7%	19.8%	17.7%
Excess Revenue Based on ROE of 8.70%	(H)	$ 97.2	$ 93.5	$ 27.7

Sources:

(A) 2013 FERC Form 1, Page 114
(B) Case No. 13-2005-EL-RDR, 11/1/2013 for Income Tax Rate
2013 FERC Form 1, Page 117 for Actual 2013 Interest
Testimony of Dr. Woolridge for Weighted Cost of Debt
(C) Case No. 14-0828-EL-UNC, Schedule KJT-2
(D) Case No. 13-2005-EL-RDR, 11/1/2013
(E) 2013 FERC Form 1, Page 232: RCP Deferrals Net of Taxes
(F) Testimony of Dr. Woolridge 0.55*0.0454*Rate Base
(G) Testimony of Dr. Woolridge 0.45*Rate Base
(H) Testimony of Dr. Woolridge

National Regulatory
Research Institute

How Should Regulators View Cost Trackers?

Ken Costello, Principal

National Regulatory Research Institute

September 2009

09–13

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Online Access

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

Executive Summary

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

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

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

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

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

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

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

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

I. The Definition and Mechanics of a Cost Tracker

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

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

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

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

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

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

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

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

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

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

II. Principles for Cost Recovery

A. "Reasonable opportunity" criterion

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

B. Incentive effects of cost trackers

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

[16] I thank Adam Pollock for this insight.

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

[18] I thank Joseph Rogers for this insight.

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

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

III. Utilities' Perspective on Cost Trackers

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

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

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

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

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

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

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

IV. Regulatory Rationales for Cost Trackers

A. "Extraordinary circumstances"

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

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

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

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

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

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

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

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

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

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

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

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

B. "Severe financial consequences"

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

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

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

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

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

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

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

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

C. An illustration: FACs and PGAs

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

B. No cost trackers

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

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

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

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

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

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

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

VI. Putting It All Together

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

A. The positive side of cost trackers

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

VII. Questions Regulators Should Ask

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

OCC Set 5
Witness:

Case No. 14-1297-EL-SSO
Ohio Edison Company, The Cleveland Electric Illuminating Company and The Toledo Edison Company for Authority to Provide for a Standard Service Offer Pursuant to R.C. § 4928.143 in the Form of an Electric Security Plan

RESPONSES TO REQUEST

OCC Set 5–INT-126 Referring to the July 2, 2014 pricing update of Rider DCR Filing, Revenue Requirement Calculation, Page 2, for each utility (Case Nos. 13-2005-EL-RDR, 13-2006-EL-RDR and 13-2007-EL-RDR:

a. Do the changes in the Accumulated Reserve include the effect of the accrued Asset Removal Cost included in FERC Account 254 and/or Account 230?

b. If the answer to (a) is negative, please explain why.

Response: Objection. This request seeks information that is neither relevant nor reasonably calculated to lead to the discovery of admissible evidence.

OCC Set 5
Witness:

Case No. 14-1297-EL-SSO
Ohio Edison Company, The Cleveland Electric Illuminating Company and
The Toledo Edison Company for Authority to Provide for a Standard Service Offer
Pursuant to R.C. § 4928.143 in the Form of an Electric Security Plan

RESPONSES TO REQUEST

OCC Set 5–INT-127 Referring to the July 2, 2014 pricing update of Rider DCR Filing, Revenue Requirement Calculation, for each utility (Case Nos. 13-2005-EL-RDR, 13-2006-EL-RDR and 13-2007-EL-RDR):

a. Do the changes in the ADIT balances since May 31, 2014 account for changes in the "FAS 109 Adjustment" included in FERC Account 190 and/or Account 283?

b. If the answer to (a) is negative, please explain why.

Response: Objection. This request seeks information that is neither relevant nor reasonably calculated to lead to the discovery of admissible evidence.

OCC Set 5
Witness:

Case No. 14-1297-EL-SSO
Ohio Edison Company, The Cleveland Electric Illuminating Company and The Toledo Edison Company for Authority to Provide for a Standard Service Offer Pursuant to R.C. § 4928.143 in the Form of an Electric Security Plan

RESPONSES TO REQUEST

OCC Set 5–INT-128 Referring to the July 2, 2014 pricing update of Rider DCR Filing, Revenue Requirement Calculation, for each utility (Case Nos. 13-2005-EL-RDR, 13-2006-EL-RDR and 13-2007-EL-RDR):

a. Do the changes in the ADIT balances since May 31, 2014 account for changes in the "Customer Receivables for Future Income Tax" included in FERC Account 182 net of the "Customer Receivables for Future Income Tax" included in FERC Accounts 254 and/or 283?

b. If the answer to (a) is negative, please explain why.

Response: Objection. This request seeks information that is neither relevant nor reasonably calculated to lead to the discovery of admissible evidence.