OCC EXHIBIT _______

BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of Ohio Power Company for Authority to Establish a Standard Service Offer Pursuant to R.C. 4928.143, in the Form of an Electric Security Plan.	)))))	Case No. 13-2385-EL-SSO
In the Matter of the Application of Ohio Power Company for Approval of Certain Accounting Authority.	))	Case No. 13-2386-EL-AAM

DIRECT TESTIMONY OF DAVID J. EFFRON

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

MAY 6, 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 December 20, 2013, Ohio Power Company d/b/a AEP Ohio ("AEP Ohio " or "the Utility") filed an application with the Public Utilities Commission of Ohio ("PUCO") seeking approval of a new electric security plan ("the proposed ESP" or "ESP III"). As part of this application, AEP Ohio addressed provisions regarding its distribution service, including a request for authority to continue, modify, and/or expand certain distribution service riders presently in effect and to implement a new Sustained and Skilled Workforce Rider ("SSWR"). My testimony addresses the Utility's Distribution Investment Rider ("DIR") and its proposal to implement the SSWR.

Q10. DOES YOUR TESTIMONY ON THE UTILITY'S PROPOSALS REGARDING ITS DISTRIBUTION RIDERS MEAN THAT YOU AGREE THAT THE NUMEROUS RIDERS PRESENTLY IN EFFECT FOR AEP OHIO 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 incentivize 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.

AEP Ohio has presented little evidence 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, AEP Ohio 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. A report by the National Research Regulatory Asset ("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 (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 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 utility rates and revenues (collected by the utility) even when a regulated utility company does not have a revenue deficiency. In this regard, it is worth noting that, based on my calculations, AEP Ohio earned a return on equity (exclusive of the effect of asset impairment charges) of 11.2% in 2011, 11.8% in 2012 and 11.4% in 2013 (Schedule DJE-1), as compared to the stipulated combined return on equity of 10.20% in Case Nos. 11-351-EL-AIR and 11-352-EL-AIR and the 10.65% return on equity requested by the Utility in the present case.

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 present rates were taken into consideration. If it were determined that the rates in effect were already producing an adequate return, then no rate increase would be authorized.

III. DISTRIBUTION INVESTMENT RIDER

Q13. PLEASE DESCRIBE THE DISTRIBUTION INVESTMENT RIDER ("DIR") THAT CUSTOMERS PAY NOW AS PART OF THEIR ELECTRIC SERVICE.

A13. The PUCO approved the DIR (that customers presently pay) as part of the Utility's ESP II in Case No. 11-346-EL-SSO, et al.[1] The purpose of this DIR is to collect from customers the incremental revenue requirement associated with increases in net distribution plant since August 31, 2010 (the date certain in Case Nos. 11-351

[1] *In the Matter of Columbus Southern Power and Ohio Power Company, Inc.*, Case No. 11-346-EL-SSO, Opinion and Order at 42-47 (August 8, 2012).

and 11-352, the most recent base distribution rate cases at the time of the implementation of the DIR) through May 31, 2015.

Q14. WHAT ARE THE COMPONENTS OF THE DISTRIBUTION INVESTMENT RIDER REVENUE REQUIREMENT?

A14. There are three components of the revenue requirement for the DIR. The first component is the return on the increase in net rate base, 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 service.

Q15. IS AEP OHIO PROPOSING ANY CHANGES TO THE CALCULATION OF THE DISTRIBUTION INVESTMENT RIDER REVENUE REQUIREMENT?

A15. Yes. The Utility is proposing certain modifications and expansions to the present DIR formulation. First, AEP Ohio is proposing certain technical adjustments to the calculation of the DIR revenue requirement. Second, the Utility is proposing to roll the Phase 1 gridSMART assets into the distribution plant included in the DIR revenue requirement. Third, the Utility is proposing to expand the DIR to include increases in general plant. If the PUCO approves the DIR as proposed, then these changes will go into effect on June 1, 2015, when the present DIR expires.

Q16. PLEASE DESCRIBE THE TECHNICAL ADJUSTMENTS TO THE DISTRIBUTION INVESTMENT RIDER REVENUE REQUIREMENT AS PROPOSED BY AEP OHIO.

A16. Originally, the Utility calculated a single carrying charge factor by adding together the pre-tax rate of return (cost of capital), the composite depreciation rate, and the property tax rate. The revenue requirement was then determined by applying that carrying charge rate to the increase in gross distribution plant in service, less the increase in related accumulated depreciation and accumulated deferred income taxes ("ADIT"). This formula was subsequently modified so that the carrying charge rate was applied to the net incremental plant in service and a separate credit was calculated by applying the pre-tax rate of return to the incremental ADIT. The Utility is now proposing to apply each component of the carrying charge factor separately to the relevant base for the individual factor. The base to which each factor of the carrying charge is applied is different.

The pre-tax rate of return would be applied to the increase in gross distribution plant in service, less the increase in related accumulated depreciation and accumulated deferred income taxes, or the increase in net rate base. The composite depreciation rate would be applied to the increase in gross distribution plant in service. The property tax rate would be applied to the increase in gross distribution plant in service net of the increase in related accumulated depreciation, or the increase in net plant.

Q17. ARE THE TECHNICAL ADJUSTMENTS BEING PROPOSED BY AEP OHIO APPROPRIATE?

A17. I agree that the rate of return should be applied to the increase in net rate base and that the composite depreciation rate should be applied to the increase in gross distribution plant in service. However, the calculation of the property tax component of the total revenue requirement should be modified.

Q18. HOW SHOULD THE CALCULATION OF THE DISTRIBUTION INVESTMENT RIDER REVENUE REQUIREMENT IN REGARD TO PROPERTY TAXES BE MODIFIED?

A18. In response to OCC INT-14-324 (Attachment 2), the Utility stated that the property tax rate included in the total DIR carrying charge rate is based on the ratio of property taxes to net plant, rather than on the ratio of property taxes to gross plant, because property taxes are assessed on net plant. This is not exactly correct. The starting point for the property tax assessment is gross plant. After subtracting certain exclusions, "Percent Good" factors[2] are applied to the adjusted plant in service based on the age of the plant in order to calculate the value of taxable property. The effect of applying the Percent Good factor is to recognize plant age and the deterioration of the plant value over time. However, the Percent Good factors are not based on the Utility's book depreciation rates or on the growth in

[2] See the response to OCC INT-14-325 (Attachment 3). The Percent Good factors are set percentages applied to each vintage of property in the Annual Report to the Ohio Department of Taxation, which serves as the basis of the property tax valuation. The older the vintage, the lower the Percent Good factor. The Percentage Good factors are not particular to AEP Ohio, and they are not dependent on AEP Ohio's book depreciation reserve.

the book balance of accumulated depreciation over time. The book depreciation reserve does not enter in the determination of the value of taxable property.

In particular, the Utility is presently amortizing an excess in its book depreciation reserve at the rate of $34,910,000 per year, or $2,909,000 per month (response to OCC INT-14-321 (Attachment 4)). This amortization reduces the Utility's book depreciation reserve accordingly. There is no corresponding recognition of the amortization of the excess depreciation reserve in the calculation of the value of taxable property for property tax purposes. In effect, by applying the property tax rate to the plant in service net of the book depreciation reserve, the Utility is calculating property tax expense on the cumulative amortization of the excess depreciation reserve. This is not what actually happens. The Utility's method of calculating property tax expense overstates the property expense attributable to growth in distribution plant.

Instead, when calculating the base to which the property tax rate is applied, the depreciation reserve should be adjusted to eliminate the cumulative amortization of the excess depreciation reserve since December 31, 2011 (when rates in Case Nos. 11-351-EL-AIR and 11-352-EL-AIR went into effect). This will reflect the change in the base on which property taxes are calculated more accurately. It has the effect of increasing the depreciation reserve and reducing the net plant to which the property tax rate of 5.66% is applied in the calculation of the DIR revenue requirement.

Q19. ***CAN YOU ILLUSTRATE THE EFFECT OF YOUR PROPOSED MODIFICATION TO THE PROPERTY TAX CALCULATION ON THE DISTRIBUTION INVESTMENT RIDER REVENUE REQUIREMENT?***

A19. Yes. The DIR for September 2013 shows gross plant in service of $3,810,709,000 and accumulated depreciation of $1,411,338,000, resulting in net plant of $2,399,371,000. September 30, 2013 is 21 months after December 31, 2011. The depreciation reserve for the purpose of calculating property taxes should be increased by 21 x $2,909,000, or $61,089,000, to eliminate the cumulative amortization of the excess depreciation reserve, and the net plant to which the property tax rate of 5.66% is applied should be reduced accordingly. The DIR revenue requirement for September 2013 would be reduced by $3,458,000. The annual revenue requirement effect will increase over time by approximately $494,000 per quarter, as the cumulative amortization of the excess depreciation reserve increases (so, for example, the annual revenue requirement for the December 2013 DIR would be $3,952,000 less than it would otherwise be).

Q20. ***WHY IS THE UTILITY PROPOSING TO COLLECT THE COSTS OF THE GRIDSMART PHASE I ASSETS FROM CUSTOMERS THROUGH THE DISTRIBUTION INVESTMENT RIDER?***

A20. In response to OCC INT-2-019 (Attachment 5), AEP Ohio stated that as "there will be no additional assets recorded to the gridSMART Phase I plan and the audit of the final year assets will be complete, the Company is proposing to include those assets as part of the DIR." The Utility is proposing to eliminate the gridSMART Phase I rider, transfer the collection of those costs to the DIR, and implement a new gridSMART Phase II rider.

Q21. IS THIS ADEQUATE JUSTIFICATION FOR THE COSTS OF THE GRIDSMART PHASE I ASSETS TO BE INCORPORATED INTO THE DISTRIBUTION INVESTMENT RIDER THAT CUSTOMERS PAY?

A21. No. In Case No. 11-346-EL-SSO, the Utility also sought to include the gridSMART costs in the DIR. The PUCO emphatically rejected this request, stating that "the gridSMART projects shall be separate and apart from the DIR mechanism and projects."[3] In rejecting the Utility's request, the PUCO appeared to implicitly adopt the PUCO Staff's position that "gridSMART related cost not be recovered through the DIR, so as to better facilitate the tracking of gridSMART expenditures and savings and benefits of the gridSMART project."[4]

AEP Ohio has not explained why it would be better or administratively more efficient to collect the costs of the gridSMART Phase I assets from customers as part of the DIR charge rather than continuing to collect those costs as part of a continuing gridSMART rider that would cover both Phase I and Phase II. Although AEP Ohio Witness Moore's Exhibit AEM-1 shows the gridSMART Phase I rider being eliminated and a proposed new gridSMART Phase II rider, the "new" gridSMART rider does not appear to be in substance different from a

[3] *In the Matter of Columbus Southern Power and Ohio Power Company, Inc*., Case No. 11-346-EL-SSO, Opinion and Order at 46 (August 8, 2012).

[4] Id. at 45.

continuation of the present gridSMART rider, except that the recovery of the Phase I costs would be transferred to the DIR. Further, the Utility has not explained why the PUCO Staff's preference for keeping the gridSMART costs separate from the DIR to better facilitate tracking of gridSMART costs and benefits is no longer relevant. Accordingly, the DIR should not be expanded to include collection of gridSMART costs. Based on the gridSMART net plant as of September 30, 2013, elimination of the costs of the gridSMART Phase I assets from the DIR plant reduces the DIR revenue requirement by approximately $3.5 million. That amount would be offset by revenues collected from customers through the gridSMART rider.

Q22. WHY IS AEP OHIO PROPOSING TO EXPAND THE DISTRIBUTION INVESTMENT RIDER TO INCLUDE COSTS OF ADDITIONS TO GENERAL PLANT?

A22. In response to OCC INT-8-131(Attachment 6), AEP Ohio stated that the general plant additions to be included in the DIR "are capital additions that support distribution operations," and more specifically that inclusion of general plant additions in the DIR would provide the Company with "a mechanism to recover the cost of the replacement radio system." The replacement radio system is also addressed in the direct testimony of AEP Witness Dias and the response to Staff Data Request 8-002 (Attachment 7). As described by Mr. Dias, the new system will replace the current system, which was installed in the early 1990's and has become obsolete. Based on the Utility's testimony and responses to interrogatories and data requests, the collection of costs from customers related to the replacement system appears to be the main factor underlying the proposal to expand the DIR to include additions to general plant.

Q23. SHOULD THE DISTRIBUTION INVESTMENT RIDER THAT CUSTOMERS PAY BE EXPANDED TO INCLUDE COSTS FOR ADDITIONS TO GENERAL PLANT?

A23. No. It is my understanding that riders such as the DIR have been implemented under the PUCO authority to approve electric security plans including provisions regarding distribution infrastructure and modernization incentives for the electric distribution utility. General plant, as the name implies, is plant that relates to the general operations of the utility. While it is true that general plant can support distribution operations, that plant, as the title implies, also supports other utility functions.

General plant is not distribution infrastructure and does not relate to the modernization of that infrastructure. While additions to general plant may indirectly lead to improved electric service reliability, such additions do not represent upgrades of distribution infrastructure. As explained in the testimony of Mr. Dias, the new radio system is being installed because the current system has become obsolete. It is also overloaded and subject to increasing failure rates, and it is difficult to find replacements for parts that fail or become obsolete. Based on this description, the replacement to the current radio would be necessary independent of any improvements to the Utility's distribution infrastructure.

While no cost/benefit analysis of the replacement of the radio system has been prepared (see response to OCC RPD-2-017 (Attachment 8)), it is clear from AEP Ohio's description that the new system should improve efficiency and functionality, with attendant reductions to expenses. As noted in the response to Staff DR-8-002 (Attachment 7), the new system will prevent or reduce electrical outages, facilitate communications between the field crews and the office or dispatch center, provide communication infrastructure for specific distribution plant projects, and facilitate communications during outages and emergencies. Any cost savings associated with these enhanced capabilities will not flow through the DIR, but the costs of the new system will if additions to general plant are included in the DIR. Thus, inclusion of the new radio system in the DIR would treat the costs and benefits of the system asymmetrically, with AEP Ohio collecting the costs of the system from customers while retaining the benefits for shareholders.

If the PUCO authorizes the Utility to continue to collect the DIR charge from customers, then the Utility should not be permitted to expand the DIR charge by including the costs of additions to general plant. Based on the Utility's forecast of additions to general plant in the years 2015-2018, exclusion of general plant from the DIR would result in the annual DIR revenue requirement being lower by some

$11.7 million in 2018 (as compared to the DIR revenue requirement with general plant included.)

Q24. ARE THERE CERTAIN ESTABLISHED STANDARDS FOR THE TREATMENT OF EXPENDITURES AS CAPITAL ASSETS VERSUS PERIOD EXPENSES?

A24. Yes. As a general matter, expenditures that are deemed to provide benefits of more than one year or have a service life of greater than one year will be capitalized and charged to asset accounts on the balance sheet. Expenditures that are deemed to provide benefits or have a service life of one year or less will be treated as period costs and charged to expense accounts.

Typically, capitalized assets will be depreciated or amortized over their useful lives. For a regulated utility, to the extent that capitalized expenditures are included in plant accounts that are considered to be used and useful in providing service, those assets will be included in the utility's rate base, and the depreciation expense will be included in operating expenses. Expenditures that are considered to be period costs will be directly included in operating expenses. For ratemaking purposes, the utility will earn a return on and a return of capitalized expenditures over their useful lives, and expenses will be included in the revenue requirement as incurred.

Often, whether a particular expenditure should be treated as a capital item or as an expense is a matter of judgment. This is particularly true with regard to expenditures that entail the replacement of assets. To avoid undue refinement and complication, all property expenditures are considered to be either retirement units or minor items of property. (See Electric Plant Instruction 10 of the FERC Uniform System of Accounts.) When a retirement unit is replaced, the cost of the replacement will be added to the appropriate plant account. When a minor item of property is replaced, the cost of the replacement will be charged to maintenance expense. Regulated utilities maintain lists of retirement units that define expenditures that are to be capitalized.

Q25. HAS THE UTILITY MODIFIED ANY OF ITS CAPITALIZATION POLICIES IN RECENT YEARS?

A25. Yes. In response to OCC INT-2-009 (Attachment 9), AEP Ohio identified several changes in definitions of retirement units and/or minor units of property with regard to distribution plant since 2008. As can be seen in the response to OCC INT-9-152 (Attachment 10), the effect of these changes has been, on balance, to increase the amount of expenditures capitalized, as opposed to being expensed, in the years 2011, 2012, and 2013.

Q26. DO ANY OF THE CHANGES IN AEP OHIO'S CAPITALIZATION POLICY (DESCRIBED IN THE RESPONSE TO OCC INT-2-009) APPEAR TO BE INAPPROPRIATE?

A26. The modified capitalization policies described in the response to OCC INT-2-009 (Attachment 9) do not appear to be improper in and of themselves. However, the timing of the changes raises a potential problem of double recovery of certain expenditures.

Q27. PLEASE EXPLAIN HOW THE TIMING OF THE MODIFICATIONS TO AEP OHIO'S CAPITALIZATION POLICIES COULD RESULT IN A DOUBLE RECOVERY OF CERTAIN COSTS FROM CUSTOMERS.

A27. The changes in capitalization policy identified in the response to OCC INT-2-009 (Attachment 9) entailed the capitalization of expenditures that had been previously charged to expense. As can be seen in the response to OCC INT-9-152 (Attachment 10), these changes affected the treatment of expenditures for manhole tops and external link boxes from September 2011 through September 2013. The test year in Case Nos. 11-351-EL-AIR and 11-352-EL-AIR, the Utility's most recent distribution rate cases, was for twelve months ending on May 31, 2011. Thus, the effect of the changes to the capitalization policy was not reflected in the test year in those cases. Any costs covered by the changes in capitalization policy (that is, manhole top and/or external link box) would have been treated as maintenance in the twelve months ending on May 31, 2011 and included as current, annual, ongoing expenses in the determination of the Utility's revenue requirement. The Utility is already recovering such costs in rates each year as ongoing expenses for as long as the rates established in Case Nos. 11-351-EL-AIR and 11-352-EL-AIR are in effect. By capitalizing these costs and including them in distribution plant since the resolution of the last base rate cases, the Utility is also collecting a return on and of those same expenditures in the DIR, resulting in a double recovery. Similarly, any other changes in accounting policy going forward that capitalize expenditures that had previously been charged to expense could also result in a double recovery of such expenditures from customers.

Q28. WHAT DO YOU RECOMMEND TO ADDRESS THIS PROBLEM OF DOUBLE RECOVERY OF COSTS FROM CUSTOMERSAS A RESULT OF CHANGES IN CAPITALIZATION POLICY?

A28. First, the costs capitalized as a result of the changes in accounting policy since the end of the test year in Case Nos. 11-351-EL-AIR and 11-352-EL-AIR should be removed from the distribution plant used in the calculation of the DIR revenue requirement. The effect of eliminating these expenditures from the DIR plant has the effect of reducing the DIR revenue requirement by approximately $0.2 million annually, which is not especially material compared to the total DIR revenue requirement. However, second, and more importantly, any further changes in accounting policy that affect the capitalization of expenditures should be subject to PUCO approval. Any change in the Utility's capitalization policies should then be synchronized with the ratemaking treatment, so that the relevant expenditures will not be capitalized at the same time that they are being collected from customers in rates as current expenses.

Q29. PLEASE SUMMARIZE THE EFFECT OF YOUR RECOMMENDATIONS REGARDING THE PROPOSED DISTRIBUTION INVESTMENT RIDER.

A29. I have summarized the approximate revenue requirement effects of my DIR recommendations on Schedule DJE-2. The revenue requirements effects are necessarily estimates and will change over time, so they should be considered only approximations of the order of magnitude of the effect of these recommendations.

Q30. HAVE YOU ALSO QUANTIFIED THE EFFECT OF THE RATE OF RETURN RECOMMENDATION BY DR. WOOLRIDGE?

A30. Yes. Dr. Woolridge is recommending a return on equity of 8.875%. This results in a weighted average rate of return 7.39%, which becomes 9.58% when grossed up for income taxes. Based on the September 30, 2013 DIR, Dr. Woolridge's recommendation would reduce the DIR revenue requirement by $1,006,000.

IV. SUSTAINED AND SKILLED WORKFORCE RIDER

Q31. IS THE UTILITY SEEKING PUCO APPROVAL TO CHARGE CUSTOMERS THROUGH A NEW RIDER FOR OPERATION AND MAINTENANCE EXPENSES ASSOCIATED WITH NEW DISTRIBUTION EMPLOYEES ?

A31. Yes. The Utility is proposing a new Sustained and Skilled Workforce Rider ("SSWR"). As described in the testimony of Mr. Dias, the SSWR would recover the incremental operation and maintenance ("O&M") expenses of new employees necessary to support future work requirements while reducing the reliance on contract labor to meet those work requirements.

***Q32. SHOULD THE UTILITY'S PROPOSAL TO COLLECT A SUSTAINED AND SKILLED WORKFORCE RIDER CHARGE FROM CUSTOMERS BE APPROVED*?**

A32. No. The costs to be collected through SSWR do not meet any of the above described criteria for costs that should be subject to recovery through a rider. First, the expenses of new employees are clearly within the control of the Utility. Second, the expense of new employee positions is not volatile or subject to unpredictable fluctuations. Third, while the forecasted expenses are not immaterial, for a utility the size of AEP Ohio, they are not expenses of a magnitude that should qualify for automatic collection from customers through a rider. As shown on Table 5 of the testimony of Mr. Dias, the Utility is forecasting costs to be collected from customers through the SSWR of $1.5 million beginning in 2015, increasing to $8.0 million in 2018.

Finally, if the costs attributed to adding new employees are permitted to be collected from customers through a rider, then this might create an incentive for the Utility to add employees rather than implement a potentially less costly alternative. As the PUCO Staff noted, in Case No. 07-1080-GA-AIR, when Vectren Energy Delivery of Ohio sought to implement alternative regulation to recover the costs of hiring new employees to address an aging workforce, these costs "should be subject to normal regulation practices for test year expenses."[5]

Q33. ARE THERE ANY OTHER REASONS WHY THE NEW EMPLOYEE OPERATION AND MAINTENANCE EXPENSES SHOULD NOT BE COLLECTED FROM CUSTOMERS THROUGH A SEPARATE RIDER?

A33. Yes. The Utility has not clearly established the criteria for determining whether the new employees will actually result in incremental O&M expenses. If the addition of new employees is offset by the retirement of employees elsewhere, the addition of the new employees will not increase the total employee complement and actual labor expense. Similarly, if the addition of new employees is offset by reductions to outside contractors, the total O&M expense incurred by the Utility will not increase as a result of the employee additions. In response to OCC INT-14-327 (Attachment 11), the Utility stated that the SSWR will include incremental positions for front-line construction and construction support added after the complement baseline positions as of the date its application was filed. However, AEP Ohio has not described how any potential offsetting reductions to the cost of the new SSWR employees would be taken into account.

[5] *In the Matter of Vectren Energy Delivery of Ohio, Inc.*, Case Nos. 07-1080-GA-AIR and 07-1080-GA-ALT, Staff Report at 10 (June 16, 2008).

Q34. WHAT DO YOU RECOMMEND REGARDING THE PROPOSED SUSTAINED AND SKILLED WORKFORCE RIDER?

A34. AEP Ohio has not established that the SSWR is either necessary or appropriate, or that a rider is the proper mechanism to collect new employee costs from customers. It should not be approved.

V. CONCLUSION

Q35. PLEASE SUMMARIZE YOUR TESTIMONY.

A35. If the PUCO approves the continuation of the DIR, the calculation of the property tax expense should be modified to eliminate the cumulative amortization of the excess depreciation reserve from the determination of the net distribution plant balance to which the property tax rate is applied. The DIR should not be expanded to include costs from gridSMART additions or general plant additions. Any changes in accounting policy that affect the capitalization of expenditures should be subject to PUCO approval. The proposed new SSWR should not be approved.

Q36. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A36. 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 6th day of May, 2014.

/s/ Maureen R. Grady
Maureen R. Grady
Assistant Consumers' Counsel

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Schedule DJE-1

OHIO POWER COMPANY D/B/A AEP OHIO.
CASE NOS. 13-2385-EL-SS0, 13-2386-EL-AAM
EARNED RETURN ON EQUITY
($MILLION)

	2011	2012	2013
Net Income Available for Common Equity	$ 410.0	$ 343.5	$ 463.7
Asset Impairment Charges (Net of Tax)	100.3	186.6	58.4
Adjusted Net Income Available for Common Equity	510.3	530.1	522.1
Average Common Equity	$ 4,552.4	$ 4,488.0	$ 4,578.2
Earned Return on Common Equity	11.2%	11.8%	11.4%

Source: Ohio Power Company and Subsidiaries 2013 Annual Report
2013 exclusive of the year-end generation distribution to parent

Schedule DJE-2

OHIO POWER COMPANY D/B/A AEP OHIO.
CASE NOS. 13-2385-EL-SS0, 13-2386-EL-AAM
REVENUE REQUIREMENT EFFECT OF DIR ISSUES
($000)

Issue		Plant Adjustment	(6) Factor	Rev Req Effect
Amortization of Excess Deprec. Reserve	(1)	(61,089)	5.66%	(3,458)
GridSmart Phase I Assets	(2)	(17,495)	20.20%	(3,534)
General Plant	(3)	(57,800)	20.20%	(11,676)
Change in Capitalization Policy	(4)	(1,005)	20.20%	(203)
Return on Equity	(5)			(1,006)

Sources:

(1)	Monthly Amortization	2,909	OCC INT-14-321
	Months 12/11 - 9/13	21	
	Effect on Property Tax Base	(61,089)	
(2)	DIR September 2013		
(3)	Dias Testimony, Page 16, Cumulative through 2018		
(4)	Response to OCC INT-9-152		
(5)	Net Change in Distribution Plant	262,521	DIR September 2013
	ADIT Offset	183,765	DIR September 2013
	Net Change in Distribution Rate Base	78,756	
	Pre-Tax ROR - OCC	9.58%	Dr. Woolridge
	Pre-Tax ROR - AEP Ohio	10.86%	Exhibit RVH-1
	Difference	-1.28%	
	Revenue Requirement Effect	(1,006)	
(6)	Exhibit AEM-2, Page 1		

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.

Table of Contents

How Should Regulators View Cost Trackers?

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

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

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

I. The Definition and Mechanics of a Cost Tracker

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

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

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

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

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

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

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

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

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

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

II. Principles for Cost Recovery

A. "Reasonable opportunity" criterion

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

B. Incentive effects of cost trackers

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

[16] I thank Adam Pollock for this insight.

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

[18] I thank Joseph Rogers for this insight.

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

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

III. Utilities' Perspective on Cost Trackers

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

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

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

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

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

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

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

IV. Regulatory Rationales for Cost Trackers

A. "Extraordinary circumstances"

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

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

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

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

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

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

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

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

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

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

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

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

B. "Severe financial consequences"

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

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

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

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

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

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

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

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

C. An illustration: FACs and PGAs

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

B. No cost trackers

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

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

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

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

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

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

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

VI. Putting It All Together

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

A. The positive side of cost trackers

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

VII. Questions Regulators Should Ask

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

OHIO POWER COMPANY'S RESPONSE
THE OFFICE OF THE OHIO CONSUMERS' COUNSEL'S
DISCOVERY REQUEST
PUCO CASE NO. 13-2385-EL-SSO et al.
FOURTEENTH SET

INTERROGATORY

INT-14-324 Referring to the response to OCC-RPD 2-20, Attachment 1, why is the property tax rate included in the total DIR carrying charge rate based on the ratio of property taxes to net plant rather than on the ratio of property taxes to gross plant?

RESPONSE

Property Taxes are assessed on net plant.

Prepared By: Andrea E. Moore

OHIO POWER COMPANY'S RESPONSE
THE OFFICE OF THE OHIO CONSUMERS' COUNSEL'S
DISCOVERY REQUEST
PUCO CASE NO. 13-2385-EL-SSO et al.
FOURTEENTH SET

INTERROGATORY

INT-14-325 Please identify the actual assessed value of distribution property for property tax purposes as a percentage of the book value of distribution property (property tax valuation percentage) for each year 2010 – 2013. The response should include supporting calculations.

RESPONSE

See OCC INT 14-325 Attachment 1 for property tax book value and assessed value comparisons, calculations of average tax rates and supporting calculations.

Prepared by: Thomas E. Mitchell

OHIO POWER COMPANY'S RESPONSE
THE OFFICE OF THE OHIO CONSUMERS' COUNSEL'S
DISCOVERY REQUEST
PUCO CASE NO. 13-2385-EL-SSO et al.
FOURTEENTH SET

INTERROGATORY

INT-14-321 Referring to the response to OCC INT 9-146, why is the proper amount of amortization $3,228,836 per month, as such amount includes amortization of the depreciation reserve excess on general plant, and the current DIR does not include general plant?

RESPONSE

$3,228,836 should not be used since general plant is not included. $3,055,000 shown in Staff 1-2 should be $2,909,171.

Prepared By: Andrea E. Moore

OHIO POWER COMPANY'S RESPONSE TO
THE OFFICE OF THE OHIO CONSUMERS' COUNSEL'S
DISCOVERY REQUEST
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SECOND SET

INTERROGATORY

INT-2-019 Referring to the Direct Testimony of Andrea Moore, at page 7, please explain why the Company is proposing to incorporate the gridSMART Phase I assets into the DIR.

RESPONSE

The gridSMART Phase I project will end after a final true-up of assets acquired through December 2013. Currently the DIR removes the net book value associated from these assets. Because there will be no additional assets recorded to the gridSMART Phase I plan and the audit of the final year assets will be complete, the Company is proposing to include those assets as part of the DIR.

Prepared By: Andrea E. Moore

OHIO POWER COMPANY'S RESPONSE
THE OFFICE OF THE OHIO CONSUMERS' COUNSEL'S
DISCOVERY REQUEST
PUCO CASE NO. 13-2385-EL-SSO et al.
EIGHTH SET

INTERROGATORY

INT-8-131 Referring to the response to OCC INT 2-015, why are you proposing to expand the DIR to include the general plant additions described on Page 19 of Mr. Dias's testimony?

RESPONSE

Like the distribution plant additions already included in the DIR, the Company is requesting the general plant additions attributed to distribution also be included in the DIR. These distribution general plant additions are capital additions that support distribution operations. As described in the Dias Prefiled Direct Testimony, page 19, line 13, the Company will need to replace the 800 MHz Radio system during the term of the ESP III. By including the general plant additions in the DIR, it will provide the Company a mechanism to recover the cost of the replacement radio system. See the response to Staff DR-8-001 for further explanation.

Prepared by: Selwyn J. Dias

OHIO POWER COMPANY'S RESPONSE
TO THE PUBLIC UTILITIES COMMISSION OF OHIO'S
DATA REQUEST
PUCO CASE NO. 13-2385-EL-SSO et al.
STAFF BAKER SET (8)

DATA REQUEST

DR-8-002 Also concerning AEP's response to DR 3-4, please describe how AEP's planned project to replace the 800 Mhz radio system will tend either to reduce or prevent the occurrence of electrical outages or will otherwise lead to improved electric reliability.

RESPONSE

The response to DR-8-01 is applicable to this question as well. The 800 Mhz radio system is another example of a general plant project whose function provides support, so crews are able to perform specific distribution plant projects that either reduce or prevent the occurrence of electrical outages or will otherwise lead to improved electric reliability. The 800 Mhz radios facilitate communications between the field crews and the office or dispatch center. Crews must be able to speak with the dispatcher to perform switching to isolate lines or equipment that may be required for a specific distribution plant project. Similarly, crews may need to contact the office for issues related to a specific distribution plant project. Additionally, the radio system provides the communication infrastructure for specific distribution plant projects that may require communication with remote devices. Finally, the radios facilitate communications and GPS locating capabilities during outages and emergencies.

Prepared by: Selwyn J. Dias

OHIO POWER COMPANY'S RESPONSE TO
THE OFFICE OF THE OHIO CONSUMERS' COUNSEL'S
DISCOVERY REQUEST
PUCO CASE NO. 13-2385-EL-SSO et al.
SECOND SET

INTERROGATORY

INT-2-017 Referring to the Direct Testimony of Andrea Moore, at pages 5-6, please explain how the Company will quantify general plant additions to be included in the DIR. The response should include a description of how the relevant general plant additions will be allocated to the distribution function.

RESPONSE

The DIR will only include general plant included in the Company's distribution ledger. General plant additions are directly assigned to the distribution ledger based on its use.

Prepared By: Andrea Moore

OHIO POWER COMPANY'S RESPONSE TO
THE OFFICE OF THE OHIO CONSUMERS' COUNSEL'S
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PUCO CASE NO. 13-2385-EL-SSO et al.
SECOND SET

INTERROGATORY

INT-2-009 Please identify any changes in definitions of retirement units and/or minor units of property with regard to distribution plant since 2008. The response should identify any changes to accounting policies affecting the accounting for expenditures as plant costs or expenses.

RESPONSE

Below is a list of the retirement units added to distribution plant since 2008.

Description	Plant Account	Approved	Comment
NAS Battery & Associated Equipment	36300	11/13/2008	New technology to AEP. FERC Order 784 addresses the accounting for Energy Storage Devices.
Manhole Top	36600	2/03/2011	Added for consistency.
CES Battery & Associated Equipment	36300	7/14/2011	New technology to AEP. FERC Order 784 addresses the accounting for Energy Storage Devices.
Network Protector Remote Racking Unit	36800	11/08/2011	Added for consistency.
Network Protector External Link Box	36800	11/08/2011	New technology to AEP.
Voltage Regulator Control	36200/ 36800	6/27/2013	Change in business practice at AEP using SMART circuits.
Line Monitor	36500	6/27/2013	New technology to AEP.

Below is a list of changes to retirement units and minor units of property applicable to distribution plant since 2008.

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SECOND SET

INT-2-009 CONTINUED

Change	Plant Account	Approved
Map the resistor retirement unit to station neutral grounding resistors.	36200	6/21/2011
Change the retirement unit definition for a grounding grid to below grade or above grade grid.	36200	9/14/2011
Capitalize the first time application of epoxy sealant to an underground vault.	36600	10/03/2012
Map the SCADA retirement unit to station equipment.	36200	10/01/2013

OHIO POWER COMPANY'S RESPONSE
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NINTH SET

INTERROGATORY

INT-9-152 Referring to the response to OCC INT 2-009, for each addition or change in 2011, 2012, and 2013, please quantify the additions to plant as a result of the changes. The response should also identify any effect on expenses resulting from each change.

RESPONSE

See attached file, OCC INT-9-152 Attachment 1.pdf, for amounts capitalized using the new retirement units. The manhole top and external link box were the only retirement units that had activity.

Prepared by: Selwyn J. Dias

Ohio Power Company
Plant Additions
Resulting from Change

company	retirement_unit	utility_account	month_number	activity_cost
Columbus Southern Power - Distr	Manhole Top	36600 - Underground Conduit	201109	67,917.72
Columbus Southern Power - Distr	Manhole Top	36600 - Underground Conduit	201110	688,610.83
Columbus Southern Power - Distr	Manhole Top	36600 - Underground Conduit	201111	5,235.61
Columbus Southern Power - Distr	Manhole Top	36600 - Underground Conduit	201112	91,483.48
			2011 Total	**853,247.64**
Columbus Southern Power - Distr	Manhole Top	36600 - Underground Conduit	201201	5,537.30
Columbus Southern Power - Distr	Manhole Top	36600 - Underground Conduit	201202	9,534.12
Ohio Power - Distr	Manhole Top	36600 - Underground Conduit	201202	17,249.72
Ohio Power - Distr	Manhole Top	36600 - Underground Conduit	201205	5,847.78
Ohio Power - Distr	Manhole Top	36600 - Underground Conduit	201206	29.54
Ohio Power - Distr	Manhole Top	36600 - Underground Conduit	201210	24,772.83
Ohio Power - Distr	Manhole Top	36600 - Underground Conduit	201211	4,860.32
Ohio Power - Distr	Manhole Top	36600 - Underground Conduit	201212	103.24
			2012 Total	**67,934.85**
Ohio Power - Distr	External Link Box	36800 - Line Transformers	201305	31,470.29
Ohio Power - Distr	External Link Box	36800 - Line Transformers	201306	258,050.77
Ohio Power - Distr	External Link Box	36800 - Line Transformers	201307	47,627.83
Ohio Power - Distr	External Link Box	36800 - Line Transformers	201309	234,836.57
Ohio Power - Distr	External Link Box	36800 - Line Transformers	201312	45,991.79
Ohio Power - Distr	Manhole Top	36600 - Underground Conduit	201303	340,694.04
Ohio Power - Distr	Manhole Top	36600 - Underground Conduit	201304	6,055.17
Ohio Power - Distr	Manhole Top	36600 - Underground Conduit	201305	127.14
Ohio Power - Distr	Manhole Top	36600 - Underground Conduit	201306	5,362.89
Ohio Power - Distr	Manhole Top	36600 - Underground Conduit	201307	8.17
Ohio Power - Distr	Manhole Top	36600 - Underground Conduit	201308	34,841.56
Ohio Power - Distr	Manhole Top	36600 - Underground Conduit	201309	262.08
			2013 Total	**1,005,328.30**

OHIO POWER COMPANY'S RESPONSE
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FOURTEENTH SET

INTERROGATORY

INT-14-327 Referring to the response to OCC INT 9-153, please explain the criteria that will be used to determine if a new hire is or is not included in the SSWR program.

RESPONSE

The SSWR will include incremental positions added after the complement baseline positions as of the filing application date. These positions and the baseline are for front-line construction and construction support as described in witness Dias's testimony.

Prepared By: Selwyn Dias