STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF NORTHERN INDIANA PUBLIC SERVICE COMPANY FOR AUTHORITY TO MODIFY ITS RATES AND CHARGES FOR ELECTRIC UTILITY SERVICE AND FOR APPROVAL OF: (1) CHANGES TO ITS ELECTRIC SERVICE TARIFF INCLUDING A NEW SCHEDULE OF RATES AND CHARGES AND CHANGES TO THE GENERAL RULES AND REGULATIONS AND CERTAIN RIDERS; (2) REVISED DEPRECIATION ACCRUAL RATES; (3) INCLUSION IN ITS BASIC RATES AND CHARGES OF THE COSTS ASSOCIATED WITH CERTAIN PREVIOUSLY APPROVED QUALIFIED POLLUTION CONTROL PROPERTY, CLEAN COAL TECHNOLOGY, CLEAN ENERGY PROJECTS AND FEDERALLY MANDATED COMPLIANCE PROJECTS; AND (4) ACCOUNTING RELIEF TO ALLOW NIPSCO TO DEFER, AS A REGULATORY ASSET OR LIABILITY, CERTAIN COSTS FOR RECOVERY IN A FUTURE PROCEEDING.	)	CAUSE NO. 44688

OFFICIAL EXHIBITS

Direct Testimony and Exhibit of

James R. Dauphinais

On behalf of

NIPSCO Industrial Group

IURC
INTERVENOR'S-IG
EXHIBIT NO. 5
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BRUBAKER & ASSOCIATES, INC.

Project 10143

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Direct Testimony of James R. Dauphinais

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Direct Testimony of James R. Dauphinais

I. Introduction

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A James R. Dauphinais. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q WHAT IS YOUR OCCUPATION?

A I am a consultant in the field of public utility regulation and a Managing Principal with the firm of Brubaker & Associates, Inc. ("BAI"), energy, economic and regulatory consultants.

Q PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A This information is included in Appendix A to my testimony.

Q **ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?**

A I am appearing on behalf of The NIPSCO Industrial Group ("Industrial Group"). Industrial Group members purchase substantial quantities of electricity from Northern Indiana Public Service Company ("NIPSCO" or "Company").

Q **WHAT IS THE SUBJECT MATTER OF YOUR DIRECT TESTIMONY?**

A My testimony will address the following issues:

- NIPSCO's Proposed Regional Transmission Organization ("RTO") adjustment rider (Rider 771);
- NIPSCO's Proposed Back-up, Maintenance and Temporary Industrial Service Rider (Rider 776);
- NIPSCO's General Terms and Conditions definition of Qualifying Facility; and
- Annual provision by NIPSCO, on July 1st of each year, of a non-binding, good faith, five-year projection of electric rates under its base rates and riders.

My silence on any aspect of NIPSCO's proposals in this proceeding should not be taken as a tacit endorsement of the positions taken by NIPSCO in this proceeding.

Q **PLEASE SUMMARIZE YOUR CONCLUSIONS AND RECOMMENDATIONS.**

A My conclusions and recommendations to the Indiana Utility Regulatory Commission ("IURC" or "Commission") are summarized as follows:

- NIPSCO's RTO adjustment rider (Rider 771) should be modified as follows:
  - All expenses and revenues except those directly related to off-system energy sales margins should be removed from Rider 771 as NIPSCO

does not have a reasonable need for a rate adjustment mechanism for those expenses and revenues;

- Assuming the aforementioned recommendation is adopted by the Commission: (i) Rider 771 should be renamed "Adjustment for Off-System Sales Margins" and (ii) the tracking of MISO Miscellaneous Amount, Revenue Neutrality and MVP Distribution expenses and revenues should be transferred to NIPSCO's Rider 770 Fuel Adjustment Clause ("FAC"); and

- NIPSCO should be required to absorb 100% of any negative off-system sales margins.

• As detailed in the body of my testimony, NIPSCO's proposed Rider 776 should be modified to:

  - Clarify NIPSCO's adjustment riders do not apply to Back-up Service and Buy-Through Temporary Service;

  - Clarify NIPSCO must confirm all Back-up Service requests that are made in full conformance with Rider 776; and

  - Set the demand charges for Rider 776 by applying the final demand charge percentage increase for Rates 732 and 733 from current Rates 632 and 633 to the current Rider 676 demand charges.

• As detailed in the body of my testimony, NIPSCO's definition of Qualifying Facility in its General Terms and Conditions and its proposed Rider 778 should be modified to be consistent with IC 8-1-2.4-2(g).

• On July 1st of each year, NIPSCO should provide a non-binding, good faith five-year projection of its electric rates under its base rates and riders.

II. NIPSCO's Proposed RTO Adjustment Rider (Rider 771)

A. *Prerequisites for Granting an Adjustment Rider*

Q SHOULD CERTAIN PREREQUISITES BE MET BEFORE A UTILITY IS GRANTED AN ADJUSTMENT RIDER?

A Yes. In general, the use of a revenue and expense rider that periodically adjusts should be avoided unless a convincing need for it has been demonstrated by the utility requesting it. There are two principal reasons why this is the case.

First, the use of such a rider allows a utility to pursue single-issue ratemaking with regard to the expenses and revenues that are tracked by a rider. With single-issue ratemaking, a utility can receive additional revenue in rates due to either an increase in a tracked expense or decrease in a tracked revenue without any consideration of whether that utility would simultaneously be experiencing offsetting decreases in expenses or offsetting increases in revenues for those expenses and revenues that are not being tracked. To put it more simply, allowing such a rider can break the synchronism among revenues, expenses and rate base.

Second, the use of such a rider eliminates the inherent incentive a utility has to minimize expenses and maximize revenues between base rate proceedings, which over time works to keep electric rates lower than they otherwise would be. When a utility is allowed to track an expense through such a rider, it can become indifferent or less vigilant, with regard to minimizing that expense since it knows it can pass on to ratepayers any increase in that expense. Similarly, when a utility is allowed to track a revenue through such a rider, it can become indifferent, or less aggressive in maximizing that revenue, since it knows that it will be able to recover any shortfall in that revenue through the rider. While prudence review of expenses and revenues includable in such riders provides some degree of incentive with respect to a utility maintaining its expenses and revenues within the range of reasonableness, it does not provide the same incentive to a utility to fully minimize its expenses and fully maximize its revenues as is provided when these expenses and revenues are only includable in base rates. Furthermore, proving imprudence is very difficult because only the utility has all of the relevant data and in practical terms the burden is on the challenger to show that the utility has not been prudent. This especially is a problem for riders due to the expedited nature of rider reconciliation proceedings.

Q WHAT SHOULD REASONABLY BE DEMONSTRATED IN ORDER FOR A UTILITY TO SHOW IT HAS A TRUE NEED FOR THE ADJUSTMENT RIDER IT PROPOSES?

A The utility would need to show that the anticipated changes in the expenses or revenues that would be tracked by the proposed rider are:

- Large enough to present a threat to the financial well being of the utility;
- Volatile; <u>and</u>
- Not able to be reasonably managed by the utility.

Q PLEASE EXPLAIN WHY THESE THREE PREREQUISITES SHOULD BE MET.

A As I have discussed, granting a utility a rider that periodically adjusts to reflect changes in only certain expenses and revenues is single-issue ratemaking and introduces cost containment disincentive issues. They should only be used when the anticipated possible changes to the revenues and expenses in question are extraordinary enough such that normal ratemaking would not provide a reasonable opportunity for the utility to earn its authorized return. The three prerequisites act together to ensure the revenues and expenses that are proposed to be tracked are in fact extraordinary enough to justify the granting of a rider that periodically adjusts rates.

The first prerequisite ensures the anticipated changes in the revenues and expenses that would be tracked are large enough such that they do present a significant financial challenge to the utility, assuming they cannot reasonably be managed by that utility.

The second prerequisite, volatility, limits tracking to circumstances where the anticipated changes in the magnitude of the expenses and revenues are large, difficult to predict and could potentially harm both the utility and ratepayers under traditional ratemaking if they cannot reasonably be managed by the utility.[1] This prerequisite helps to ensure there are benefits to both the utility and its ratepayers from tracking the expenses and revenues, assuming the expenses and revenues in question cannot reasonably be managed by the utility. For example, if the changes in the revenues and expenses in question are just anticipated to increase the utility's costs and the amount of the increase is relatively predictable, tracking those expenses and revenues would harm ratepayers because the utility would be able to recover the generally predictable increase in cost without any consideration to whether the utility's other revenues are increasing and/or the utility's other expenses are decreasing.

Finally, it is not sufficient alone to ensure (i) the anticipated changes to the revenues and expenses are extraordinary enough to present a threat to the financial well being of the utility and (ii) the anticipated changes in the revenues and expenses are large, difficult to predict and move up and down. It is also important to ensure the anticipated changes to the revenues and expenses that will be tracked in the rider cannot otherwise reasonably be managed by the utility without the requested rider. This prerequisite helps to ensure that a utility is not seeking such a rider for anticipated changes in revenues and expenses that the utility reasonably could manage through other means available to it such as hedging, forward bilateral contracting or the timing of base rate relief filings.

[1]It is important to note volatility requires recurring, difficult to predict and significant upward and downward swings in the tracked expense or revenue. An expectation of increasing costs does not alone indicate volatility. Nor do predictable recurring upward and downward swings of an expense or revenue.

Q HAVE THESE THREE PREREQUISITES, OR ONES VERY SIMILAR TO THEM, BEEN REQUIRED TO BE MET IN OTHER REGULATORY JURISDICTIONS PRIOR TO THE GRANTING OF A PERIODICALLY ADJUSTING RIDER?

A Yes. As indicated in a September 2009 Report prepared by Ken Costello, a Principal of the National Regulatory Research Institute ("NRRI"), that is titled "How Should Regulators View Cost Trackers?:"

- "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."
- "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, and (3) substantial and recurring. Historically, commissions required that all three conditions exist if a utility wanted to have costs recovered through a tracker."
- "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."

("How Should Regulators View Cost Trackers?," Ken Costello, Principal, NRRI, September 2009 at pages 8 through 11).

It should be noted this NRRI Report is critical of the loosening up by some commissions of the criteria that has been traditionally applied in determining whether or not to grant a cost tracker to a utility (*Id.* at 1). The NRRI Report is attached as Exhibit JRD-3.

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Q HAS THE COMMISSION ITSELF PREVIOUSLY OFFERED AN OPINION ON THE THREE PREREQUISITES AND RATE ADJUSTMENT MECHANISMS IN GENERAL?

A Yes. In its 2007 Regulatory Flexibility Report to the Indiana General Assembly, the Commission noted:

> "The use of both expense and capital trackers have a favorable impact on credit ratings and therefore the cost of capital for Indiana utilities. The extensive use of expense trackers in particular presents concerns. Isolating the utility from the effect of expense changes may make it indifferent to such changes, as trackers effectively shift the impact of the changes to retail customers. The premise that tracked expense are outside the control of the utility does not generally alter the fact that the customer is not at the negotiating table and therefore even more removed from controlling the expense. Traditional regulation, with its inherent lag between expenditure and recovery, serves as an expense constraint incentive which an expense tracker nullifies.
>
> Expense tracker retail rate adjustments are processed via proceedings which consider materially less than a base rate case and are often viewed as single-issue ratemaking exercises; a condition generally in opposition to core ratemaking principles. The type of expenses and revenues tracked are also susceptible to selective inclusion. A utility may seek authority to track increasing expenses while not tracking decreasing expenses. Such asymmetry provides the means to reduce utility exposure to under earnings risk, while still affording the opportunity for increased earnings through reducing non-tracked expenses. The ability to balance the utility's risk and reward through an appropriately set rate of return does not exist in expense tracker proceedings. The direct pass-through of expenses may also create affiliate transaction concerns. While the regulated utility is indifferent to increasing prices an affiliated supplier may see opportunity in such a development."
>
> (Indiana Utility Regulatory Commission 2007 Regulatory Flexibility Report to the Indiana General Assembly at page 13).

In its 2014 Annual Report, the Commission indicated:

> "An expense tracker allows retail rates to be adjusted outside the context of a base rate case to reflect changes in operating expenses. These adjustments do not include the recovery of any financing cost, but merely allow for the utility to recover what it has spent on a dollar-for-dollar basis. The pass-through of unpredictable revenues and expenses to ratepayers reduces volatility in the utility's earnings which serves to strengthen the utility's credit rating. Recovery of expenses

that are characterized as largely outside the utility's control, volatile in nature, and materially significant is the intended goal of such trackers."

(Indiana Utility Regulatory Commission 2014 Annual Report at page 39).

The Commission clearly understands the risks associated with granting rate adjustment mechanisms such as those being proposed by NIPSCO in this proceeding and that the intention in granting such mechanisms is to address changes in expenses that meet the three prerequisites.

Q **IS THE FACT THAT UTILITY HAS BEEN PREVIOUSLY GRANTED AN ADJUSTMENT RIDER FOR PARTICULAR EXPENSES AND REVENUES A BASIS FOR THE COMMISSION TO AUTOMATICALLY RENEW THE GRANTING OF THAT RIDER?**

A No. The applicant in a base rate proceeding seeking to continue the use of a rate adjustment mechanism should be required to demonstrate the prerequisites necessary to granting the mechanism have been met regardless of whether the Commission has previously granted the mechanism to the utility in a past proceeding.

B. NIPSCO's Proposed Changes to its RTO Adjustment Rider

Q **DOES NIPSCO CURRENTLY HAVE AN RTO ADJUSTMENT RIDER?**

A Yes. NIPSCO's RTO adjustment rider was first authorized in Cause No. 43526. However, the rates approved by the Commission for NIPSCO in that case were never implemented. NIPSCO's current RTO adjustment rider, Rider 671, was authorized by the Commission in Cause No. 43969 – a settled case. As a signatory to the settlement agreement, the Industrial Group did not oppose NIPSCO's proposed Rider

671 in Cause No. 43969 and did not file testimony regarding the rider in that proceeding.

While Rider 671 is titled as an RTO adjustment rider, it is actually a combination of an adjustment mechanism for non-fuel Midcontinent Independent System Operator, Inc. ("MISO") costs and an adjustment mechanism for off-system energy sales margins. For the non-fuel MISO costs portion of the rider, NIPSCO shares 100% of the difference between its actual non-fuel MISO costs and those in base rates with its customers both above and below that base. Thus, this portion of the mechanism can pass either a charge or a credit back to customers depending on whether NIPSCO's actual non-MISO costs are above or below the base rate amount for these costs.

For the off-system energy sales margin part of the rider, NIPSCO shares 50% of its actual off-system energy sales margins that are above those included in base rates and absorbs 100% of any shortfall from the base rate amount. Therefore, unlike with the non-fuel MISO cost portion of the rider, the off-system energy sales margin portion of the rider only passes a credit back to customers -- it never passes back any additional charges. Specifically, if NIPSCO's actual off-system energy sales margins are below the base rate amount, the credit passed back to customers for off-system energy sales under Rider 671 is simply set to zero – no additional charges are collected from customers due to a shortfall by NIPSCO in actual off-system energy sales margins. (NIPSCO, IURC Electric Service Tariff, Original Volume No. 12, Original Sheet No. 110, Effective 12/21/2011).

Q **PLEASE BRIEFLY DESCRIBE NIPSCO'S PROPOSED CHANGES TO ITS CURRENT RTO ADJUSTMENT RIDER (RIDER 671) UNDER ITS PROPOSED RIDER 771.**

A NIPSCO is proposing several changes to its current RTO Adjustment Rider (Rider 671) under its proposed Rider 771. First, NIPSCO is proposing to increase its base rate amount for non-fuel MISO costs from approximately $5.3 million on an annual basis to approximately $16.5 million an annual basis. Second, it is proposing to lower the base rate amount of off-system energy sales margins from approximately $7.6 million on a annual basis to approximately $4.7 million on an annual basis. Lastly, NIPSCO proposes to change the sharing mechanism for off-system energy sales margins such that when its actual off-system energy sales margins falls below its base rate amount, NIPSCO would now collect 50% of that shortfall through charges to customers under its proposed Rider 771. Under NIPSCO's current RTO adjustment rider, Rider 671, NIPSCO cannot charge customers for any shortfall in its actual off-system energy sales margins from its base rate amount for those sales margins. (Id. and Petitioner's Exhibit No. 19, Attachment 19-A, Original Sheet No. 120).

The last of NIPSCO's proposed changes, the proposal to pass onto its customers 50% of its shortfall in actual off-system energy sales margins from the base rate amount, is a significant change from the current approach for when NIPSCO's off-system sales margins fall below the base rate amount. This will enhance NIPSCO's bottom line at the cost of its customers whenever NIPSCO has a shortfall in its off-system sales margins from the base rate amount of those margins. This makes it particularly important to carefully review and reconsider NIPSCO's RTO adjustment rider as a whole including whether NIPSCO has a reasonable need for both the non-fuel MISO cost and off-system sales margin portions of the rider and whether both portions of the rider should be continued. The review should not be limited to just whether NIPSCO has proposed reasonable new base rate amounts for its non-fuel MISO costs and its off-system energy sales margins.

C. Reasonableness of Continuing the Non-Fuel MISO Cost Portion of NIPSCO's RTO Adjustment Rider

Q HAS NIPSCO PROVIDED ANY TESTIMONY IN THIS PROCEEDING SHOWING IT HAS MET THE PREREQUISITES NECESSARY TO BE GRANTED A CONTINUATION OF THE NON-FUEL MISO COSTS PORTION OF ITS RTO ADJUSTMENT MECHANISM?

A No. As I discussed in detail earlier, such adjustment mechanisms allow utilities to engage in single-issue ratemaking and eliminate the inherent incentive a utility has to try to minimize expenses and maximize revenues between base rate proceedings. As I also discussed earlier in detail, such adjustment mechanisms should only be granted when the anticipated possible changes to the revenues and expenses that would be tracked are extraordinary enough that normal ratemaking would not provide a reasonable opportunity for the utility to earn its authorized return. This can be reasonably tested by applying to expected changes in these costs the three prerequisites I have previously discussed with respect to: (i) the magnitude of any financial threat to the utility, (ii) the volatility of the expenses and revenues and (iii) the ability of the utility to manage the expenses or revenues without an adjustment rider.

Q ARE ALL OF THESE NON-FUEL MISO CHARGES TRULY NOT RELATED TO THE COST OF FUEL?

A No. Three of the charges are actually fuel related and should be recovered through NIPSCO's Rider 770 FAC rather than Rider 771. These are NIPSCO's MISO Miscellaneous Amount, Revenue Neutrality Uplift and MVP Distribution expenses and revenues.

Q PLEASE DESCRIBE THESE THREE CHARGES IN MORE DETAIL.

A The MISO Miscellaneous Amount is used by MISO to address certain special energy and operating reserve market charges or credits that occasionally need to be collected or refunded. Most of the time, this MISO charge type is zero.

The MISO Revenue Neutrality Uplift charge type recovers energy and operating reserve market charges and credits that are not recovered by other MISO market settlement charge types. It is closely related to MISO Revenue Sufficiency Guarantee ("RSG") charges, which are already tracked in NIPSCO's FAC.

The MISO MVP Distribution charge type returns Auction Revenue Right ("ARR") credits to market participants for MISO's Multi-Value Transmission Projects. This charge type is closely akin to the MISO ARR charge types that are already tracked through NIPSCO's FAC.

All three of these MISO charge types are actually fuel related and should be moved from Rider 771 to NIPSCO's FAC.

Q HOW ARE THE REMAINING NON-FUEL MISO CHARGES THAT WOULD BE TRACKED UNDER RIDER 771 EXPECTED TO CHANGE OVER THE FORESEEABLE FUTURE?

A The two largest non-fuel MISO charges that NIPSCO proposes to track through the rider are for regional transmission expenses that are anticipated to grow over the next few years, but at a relatively predictable pace that MISO annually forecasts out for 15 to 20 years. The remainder of the charges are smaller revenues and expenses that are not likely to significantly grow. They consist of MISO administrative expenses and transmission revenues that NIPSCO receives from MISO for MISO's provision of point-to-point transmission service to third-parties under MISO Schedules 7 and 8.

Q PLEASE DESCRIBE THE TWO MISO REGIONAL TRANSMISSION EXPENSES IN MORE DETAIL.

A The two MISO regional transmission expenses are MISO Schedule 26 charges and MISO Schedule 26-A charges. MISO Schedule 26 charges apply to NIPSCO for its regionally allocated share of:

- Baseline Reliability Projects of 345 kV or higher voltage that were approved by the MISO Board of Directors ("MISO Board") in MTEP12 or earlier;
- Generator Interconnection Projects of 345 kV or higher; and
- Market Efficiency Projects.

Q **WHAT IS MISO'S CURRENT INDICATIVE ESTIMATE OF TOTAL MISO SCHEDULE 26 CHARGES APPLICABLE TO THE NIPSCO TRANSMISSION PRICING ZONE?**

A I have summarized MISO's July 31, 2014 and August 3, 2015 five-year indicative estimates of MISO Schedule 26 charges in the NIPSCO transmission pricing zone in Table JRD-1 below.

TABLE JRD-1

MISO Indicative Estimate of Future Total MISO Schedule 26 Charges in the NIPSCO Transmission Pricing Zone (Millions of Dollars)

Year	MISO's July 31, 2014 Projection	MISO's August 3, 2015 Projection
2015	6.1	N/A
2016	6.2	6.3
2017	6.5	6.5
2018	6.4	6.5
2019	6.4	6.4
2020	6.3	6.4
2021	6.2	6.2
2022	6.1	6.1
2023	6.0	6.0
2024	5.9	5.9
2025	5.8	5.9
2026	5.8	5.8
2027	5.7	5.7
2028	5.6	5.6
2029	5.5	5.5
2030	N/A	5.3

Source:
http://www.misoenergy.org/_layouts/MISO/ECM/Redirect.aspx?ID=124310

These forecasted year-to-year changes (e.g., from 2016 to 2017, 2017 to 2018, 2018 to 2019, etc.) are relatively small in magnitude and, more importantly, relatively predictable since MISO updates its five-year indicative estimate at least annually. They are not large and volatile. NIPSCO does not need to continue to have an adjustment mechanism to manage changes in them.

Q PLEASE EXPLAIN NIPSCO'S MISO SCHEDULE 26-A CHARGES.

A MISO Schedule 26-A charges collect for the cost of MISO Multi-Value Transmission Projects ("MVPs"). 100% of the costs of MVPs are allocated to all load zones across the MISO footprint and to the export zone, excluding PJM, based on MWh. MISO's latest 20-year indicative estimate of its average Schedule 26-A rate along with my estimate of the NIPSCO transmission pricing zone's total annual charges during the 20-year period is presented in Table JRD-2 below.

TABLE JRD-2

Five-year MISO Indicative Estimate of the Average MISO Schedule 26-A Rate and Total Schedule 26-A Charges in the NIPSCO Transmission Pricing Zone (as of August 3, 2015)

Year	MISO's Estimate of Schedule 26-A Rate (per MWh)	MISO's Estimate of Total NIPSCO Pricing Zone Billing Units (MWh)	Total Estimated Schedule 26-A Charges in the NIPSCO Zone (Millions of Dollars)	Estimated Annual Change in Total Schedule 26-A Charges (Millions of Dollars)
2016	$0.96	20,464,423	19.6	N/A
2017	$1.38	20,628,139	28.6	9.0
2018	$1.64	20,793,164	34.1	5.5
2019	$1.90	20,959,509	39.8	5.7
2020	$1.93	21,127,185	40.8	1.0
2021	$2.00	21,296,203	42.6	1.8
2022	$1.97	21,466,572	42.3	-0.3
2023	$1.94	21,638,305	41.9	-0.4
2024	$1.90	21,811,411	41.5	-0.4
2025	$1.87	21,985,903	41.2	-0.3
2026	$1.84	22,161,790	40.8	-0.4
2027	$1.81	22,339,084	40.4	-0.4
2028	$1.78	22,517,797	40.1	-0.3
2029	$1.75	22,697,939	39.7	-0.4
2030	$1.72	22,879,523	39.4	-0.3
2031	$1.69	23,062,559	39.0	-0.4
2032	$1.66	23,247,059	38.6	-0.4
2033	$1.63	23,433,036	38.3	-0.3
2034	$1.61	23,620,500	37.9	-0.4
2035	$1.58	23,809,464	37.6	-0.3

Source: https://www.misoenergy.org/_layouts/MISO/ECM/Redirect.aspx?ID=196552

Table JRD-2 does show NIPSCO's Schedule 26-A charges are expected to rise significantly through 2019. However, this increase is far from qualifying as volatile. The MISO Schedule 26-A charges are principally driven by the construction cost of the MVPs, which is monitored by MISO and reflected in MISO's annual update of its indicative estimate of the future average MISO Schedule 26-A rate. Thus, by nature, NIPSCO's MISO Schedule 26-A charges are not volatile costs. They are costs that are expected to increase significantly through 2019, but at a predictable level whose forecast is updated at least annually based on the latest available information on construction costs. These are cost increases NIPSCO can plan for and factor into its decision with respect to when to seek base rate relief from the Commission. NIPSCO does not need an adjustment rider to manage these costs, which are generally similar in nature to NIPSCO's own capital expenditures for its own facilities.

Q WHAT DO YOU RECOMMEND TO THE COMMISSION WITH RESPECT TO THE NON-FUEL MISO COST PORTION OF NIPSCO'S PROPOSED RTO ADJUSTMENT RIDER?

A I recommend the Commission completely reject the non-fuel MISO cost portion of NIPSCO's proposed RTO adjustment rider in this proceeding. Under this recommendation, the RTO adjustment rider would become solely an adjustment mechanism for NIPSCO's off-system energy sales and, as such, the rider should be renamed "Rider 771 Adjustment for Off-System Sales Margins" if my recommendation with respect to this issue is accepted.

With respect to that recommendation, putting aside the three MISO charge types I propose to transfer to NIPSCO's FAC (MISO Miscellaneous Amount, Revenue Neutrality Uplift and MVP Distribution expenses and revenues), all of the costs that NIPSCO's proposes to track through the non-fuel MISO Cost portion of NIPSCO's proposed Rider 771, except for MISO Schedule 26-A charges, are not anticipated to be subject to significant change in the near future and the small change that is expected to occur for these costs is relatively predictable. Furthermore, even though Schedule 26-A charges are expected to significantly increase in the near future, this increase is also relatively predictable and can be managed by NIPSCO through the timing of new base rate proceedings to the extent it needs rate relief in order to have a reasonable opportunity to earn its authorized return. NIPSCO does not have a not have a need to continue to have an adjustment mechanism to manage any of these non-fuel MISO costs.

D. *Reasonableness of Continuing the Off-System Energy Sales Margins Portion of NIPSCO's RTO Adjustment Rider*

Q **HAS NIPSCO PROVIDED ANY TESTIMONY IN THIS PROCEEDING SHOWING IT HAS MET THE PREREQUISITES NECESSARY TO BE GRANTED A CONTINUATION OF THE OFF-SYSTEM ENERGY SALES PORTION OF ITS RTO ADJUSTMENT MECHANISM?**

A No. However, changes in off-system energy sales margins are much closer akin to fuel and purchased power costs than non-MISO fuel costs with respect to being a potential financial threat to NIPSCO, volatile and difficult to manage. Like with fuel and purchased power costs, which are adjusted for through NIPSCO's Fuel Adjust Clause ("FAC"), NIPSCO's off-system energy sales margins are a function of its fuel costs and wholesale market prices for electricity. For this reason, the Industrial Group does not at this time oppose continuation of the off-system energy sales margin portion of NIPSCO's RTO adjustment rider provided that the Industrial Group reserves its right to challenge NIPSCO's need for an adjustment mechanism for off-system energy sales margins in future base rate proceedings. This said, as I have previously noted, NIPSCO in this current proceeding is proposing to change its sharing mechanism for off-system sales margins by now passing onto its customers 50% of any shortfall in its off-system energy sales margins from their base rate amount.

Q WHAT DO YOU RECOMMEND TO THE COMMISSION WITH RESPECT TO NIPSCO'S PROPOSED CHANGE IN THE SHARING MECHANISM FOR OFF-SYSTEM ENERGY SALES MARGINS?

A I recommend that the Commission condition the change on NIPSCO being prohibited from passing onto its customers any net off-system energy sales losses (i.e., net negative off-system energy sales margins) that NIPSCO may incur. This recommended condition will only matter when NIPSCO's net off-system energy sales margins over a reconciliation period are negative (i.e., a loss). In that event, what would happen is that NIPSCO would be permitted to seek recovery through Rider 771 of up to 50% of the difference between the base rate amount of off-system sales margins and zero. NIPSCO would not be permitted to seek recovery of 50% of the remainder of the difference between its actual off-system sales energy margins and the base rate amount – all of which would be an off-system energy sales loss. This would be consistent with how Duke Energy Indiana's current off-system sales margin rate adjustment currently works.

III. NIPSCO's Proposed Back-up, Maintenance and Temporary Industrial Service Rider (Rider 776)

Q WHAT CHANGES HAS NIPSCO PROPOSED TO ITS CURRENT BACK-UP, MAINTENANCE AND TEMPORARY INDUSTRIAL SERVICE RIDER (RIDER 676) IN ITS PROPOSED RIDER 776?

A NIPSCO has: (i) proposed several language changes, (ii) increased the adders to the Real-Time Locational Marginal Prices ("LMPs") applicable to energy charges for Back-up Service and Buy-Through Temporary Service and (iii) increased the demand charges for Maintenance and Temporary Service.

Q **DO YOU HAVE ANY ISSUES WITH THE PROPOSED LANGUAGE CHANGES TO THE RIDER THAT HAVE BEEN PROPOSED BY NIPSCO?**

A Yes, I have two issues. First, within the "TO WHOM AVAILABLE" paragraph on Original Sheet No. 130, NIPSCO added a sentence indicating that service under the rider will be subject to NIPSCO's adjustment riders as spelled out in Appendix A of its tariff (Riders 770 (FAC), 771 (RTO), 772 (ECRM), 774 (RA), 783 (DSMA), 786 (GPR), 787 (FNCA) and 788 (TDSIC)). Second, in the first sentence under Back-up Service under CHARACTER OF SERVICE on Original Sheet No. 130, NIPSCO has inserted the phrase "the amount confirmed by Company shall be deemed firm load, subject to Curtailments."

Q **DO YOU HAVE ANY OTHER ISSUES WITH NIPSCO'S PROPOSED CHANGES?**

A Yes. The proposed demand charges for Rider 776 represent an increase of approximately 9% over current Rider 676 demand charges -- essentially the same increase in demand charges for Rates 732 and 733 from current Rates 632 and 633. To the extent the Commission's Final Order changes the proposed percent increase in the Rate 732 and 733 demand charges from those for Rate 632 and 633, that same percentage should be applied to the Rider 676 demand charges to establish the final Rider 776 demand charges.

A. *Application of NIPSCO's Adjustment Riders to Rider 776 Service*

Q **PLEASE EXPLAIN YOUR CONCERN WITH THE APPLICATION OF NIPSCO's ADJUSTMENT RIDERS TO RIDER 776 SERVICE PURSUANT TO APPENDIX A OF NIPSCO'S TARIFF.**

A I have no issue with the application of NIPSCO's adjustment riders pursuant to Appendix A of its tariff for services under the Rider 776 that have energy rates based on NIPSCO's average fuel cost. However, the application of the adjustment riders pursuant Appendix A is a major problem for the Back-up Service and Buy-Through Temporary Service because energy is priced for those two services under Rider 776 at incremental cost based on the MISO LMP plus an adder – not NIPSCO's average fuel cost.

Q **PLEASE EXPLAIN WHY IT IS INAPPROPRIATE TO APPLY NIPSCO'S ADJUSTMENT RIDERS TO RIDER 776 SERVICES THAT ARE PRICED AT THE MISO LMP PLUS AN ADDER.**

A There are two reasons. The first is customers taking these two Rider 776 services do not get the benefit of NIPSCO's generation facilities and fuel cost averaging. They are instead subject to the hourly spot wholesale market price for energy -- the MISO LMP. To require them to also pay NIPSCO FAC (Rider 770) as proposed in the language added by NIPSCO to Rider 776 (and NIPSCO's proposed language in Appendix A of its tariff), would charge these customers twice for fuel and purchased power costs. In addition, to require these customers to pay other generation and demand reduction related costs through other NIPSCO's adjustment riders as proposed under Appendix A of NIPSCO's tariff would be patently unfair because Rider 776 customers are not getting the benefit of NIPSCO's generation facilities and

NIPSCO's average fuel cost when they purchase Back-up Service and Buy-Through Temporary Service under Rider 776.

Q WHAT IS THE OTHER REASON?

A None of the costs recovered by NIPSCO's adjustment riders likely increase in an amount in excess of that already covered by the MISO LMP and the applicable adder under Rider 776 when these two services are provided by NIPSCO. For both services, the energy being provided does not come from NIPSCO's generation facilities or the power purchases NIPSCO makes to supply its other customers. The energy for these two services is directly purchased from the MISO market and this market cost is directly passed onto the customers of these two services by requiring them to pay the MISO LMP. In addition, any small cost that may be incurred incrementally for MISO settlement charges and MISO regional transmission charges is likely already recovered in the energy adder that NIPSCO collects for two services on top of the MISO LMP. Also, both services, while firm, are curtailable for reliability before any other firm customers if curtailment of interruptible service customers under Rider 775 is insufficient. For all of these reasons, Back-up Service and Buy-Through Temporary Service under Rider 776 should not be subject to NIPSCO's adjustment riders as proposed under Appendix A of NIPSCO's tariff. The adjustment riders should only apply to regular (i.e., non-buy-through) Temporary Service and Maintenance Service under Rider 776 pursuant to Appendix A of NIPSCO's tariff.

Q WHAT DO YOU RECOMMEND TO THE COMMISSION TO ADDRESS THIS ISSUE?

A I recommend that the sentence "This Rider shall be subject to other riders as identified on Appendix A" be changed to "Except for Back-up Service and Buy-Through Temporary Service, this Rider shall be subject to other Riders as identified on Appendix A." This will make it clear NIPSCO's adjustment riders do not apply to Back-Up Service and Buy-Through Temporary Service under Rider 776.

Q IS THERE ANY EXISTING COMPARABLE SITUATION TO WHAT YOU ARE PROPOSING?

A Yes. Energy for buy-through of interruptions under Rider 775 (Interruptible Industrial Service) is also priced at the MISO LMP plus an adder. It is already not subject to NIPSCO's adjustment riders. What I am proposing for Back-up Service and Buy-Through Temporary Service for Rider 776 is comparable to the current practice for buy-through of interruptions under Rider 775.

B. Confirmation of Back-up Service Request under Rider 776

Q PLEASE EXPLAIN YOUR CONCERN WITH RESPECT TO NIPSCO'S INSERTION OF THE PHRASE "THE AMOUNT CONFIRMED BY COMPANY SHALL BE DEEMED FIRM LOAD, SUBJECT TO CURTAILMENTS" IN THE FIRST SENTENCE UNDER BACK-UP SERVICE UNDER CHARACTER OF SERVICE ON ORIGINAL SHEET NO. 130.

A The phrase implies that under certain circumstances NIPSCO might not confirm a request for Back-up Service from a Rider 776 customer. This is problematic because, unlike with Maintenance Service and Temporary Service, the customer does not always know in advance when it will need to take delivery of energy since it may not begin to happen until the customer's generation facility experiences a forced outage. As a result, a request for the delivery of energy pursuant to Back-up Service under Rider 776 may only be able to be made by the customer after the beginning of the receipt of that energy. Therefore, the addition of the phrase, as proposed by NIPSCO, should be rejected unless a modification is made to clarify it.

Q WHAT DO YOU RECOMMEND TO THE COMMISSION TO ADDRESS YOUR CONCERN?

A I recommend that the Commission require NIPSCO to insert a sentence immediately following the sentence that NIPSCO proposes to modify. The sentence would state "Confirmation of a Customer request for Back-up Service under this Rider shall not be withheld by the Company provided the request for Back-up Service is made in full conformance with the terms and conditions for Back-up Service under this Rider." This would help to clarify that NIPSCO must confirm all requests for Back-up Service except for those requests that are in violation of the terms and conditions of the Rider. This should eliminate the risk of a discretionary denial of Back-up Service by NIPSCO after the Customer has already begun taking such service due to a forced outage of its generation facility.

IV. NIPSCO's General Terms and Conditions Definition of Qualifying Facility

Q PLEASE EXPLAIN THE ISSUE YOU HAVE WITH NIPSCO'S PROPOSED DEFINITION OF QUALIFYING FACILITIES UNDER ITS GENERAL RULES AND REGULATIONS.

A NIPSCO's proposed definition does not reflect a recent change in Indiana statutes that requires electric utilities to interconnect and purchase excess output from qualifying facilities larger than 80 MW in capacity. Specifically, Section 1.68 of NIPSCO's proposed General Rules and Regulations and Rider 778 would limit a Qualifying Facility, as that term is used in the NIPSCO tariff, to cogeneration and alternate energy production facilities of 80 MW of capacity or less. This is in conflict with the IC 8-1-2.4-2(g) definition of "Private Generation Project" and the provisions of IC 8-1-2.4-6 regarding Private Generation Projects (including the sale of their excess output and interconnection), which has expanded NIPSCO's existing interconnection and purchase obligations to qualifying facilities larger than 80 MW in capacity. As a result, NIPSCO's proposed tariff definition of Qualifying Facility needs to be modified to address this change in Indiana statutes or alternatively be deleted, and Rider 778 needs to be modified to conform to current law.

Q HOW DO YOU RECOMMEND THE COMMISSION ADDRESS THIS ISSUE?

A The only place in NIPSCO's proposed tariff where the defined term Qualifying Facility is used is in its proposed Rider 778. Rider 778 defines eligibility by reference to Commission rules that still reflect the 80 MW cap. Specifically, the first sentence of Rider 778 states "As shown in Appendix A, this Rider is available to Cogeneration Facilities and/or Small Power Production Facilities which qualify under the IURC Rules (170 IAC 4-4.1-1 et seq.)." Under 170 IAC 4-4.1-1(q), "qualifying facility" is defined in relevant part as "a cogeneration or alternate energy production facility of eighty (80) megawatts capacity or less." Therefore, I recommend the Commission:

- Require NIPSCO to delete the Section 1.68 definition of Qualifying Facility from its proposed tariff; and
- Require NIPSCO to modify the first sentence of Rider 778 to the following:

  As shown on Appendix A, this rider is available to Cogeneration Facilities and/or Small Production Facilities which qualify under the IURC Rules (170 IAC 4-4.1-1 et seq.), as well as to Private Generation Projects as defined by IC 8-1-2.4-2(g) (herein "Qualifying Facility").

V. Annual Five-Year Projection of NIPSCO's Electric Rates

Q YOU INDICATED IN THE SUMMARY OF YOUR TESTIMONY THAT YOU ARE RECOMMENDING THAT THE COMMISSION REQUEST NIPSCO TO PROVIDE A NON-BINDING, GOOD FAITH FIVE-YEAR PROJECTION OF ITS BASE RATES AND ADJUSTMENT RIDERS ON JULY 1ST OF EACH YEAR. PLEASE EXPLAIN WHY YOU HAVE MADE THIS RECOMMENDATION?

A The members of the Industrial Group have found that for budgeting purposes they have each had to individually attempt to project NIPSCO's electric rates. This is problematic both because: (i) they do not have ready access to NIPSCO's projections of its future capital expenditures, fuel costs, purchased power costs, off-system sales and O&M expenses and (ii) it is inefficiently duplicative for each customer to attempt to project NIPSCO's future electric rates on their own. Since NIPSCO is in the best position to project its own future electric rates, it would be far more efficient for one entity to develop such a projection than several and NIPSCO's projection could be made available to all of its customers, the Industrial Group is recommending that the Commission request NIPSCO, in consultation with the OUCC, the Industrial Group and other interested parties, to develop an annual five-year good faith projection of its electric rates and riders that would be released on July 1st of each year. In making this recommendation, the Industrial Group fully expects NIPSCO's actual rates to deviate from NIPSCO's good faith projections. Nevertheless, for customers the projections would serve a useful guide for future expectations and budgeting.

Q DO OTHER UTILITIES PROVIDE PROJECTIONS OF THEIR FUTURE ELECTRIC RATES?

A Yes. For example, Interstate Power and Light Company in Iowa regularly provides a non-binding, good faith projection of its future electric rates to its large customers. In Exhibit JRD-1, I provide a copy of a presentation from Interstate Power and Light Company giving its latest available projections of its future electric rates. Page 3 of 6 of my exhibit shows the most recent three year forecast that Interstate Power and Light Company has provided to its customers.

In addition, on a quarterly basis, Duke Energy Indiana ("Duke") has been providing a 24-month projection of its electric rates for its HLF and LLF customers. In Exhibit JRD-2, I provide a copy of the latest such projection for HLF and LLF customers. Duke's projection is quite detailed. It includes a projection for each of its rate adjustment riders on a monthly basis for the next 24 months.

VI. Conclusions and Recommendations

Q PLEASE SUMMARIZE YOUR CONCLUSIONS AND RECOMMENDATIONS.

A My conclusions and recommendations to the Indiana Utility Regulatory Commission ("IURC" or "Commission") are summarized as follows:

- NIPSCO's RTO adjustment rider (Rider 771) should be modified as follows:

- All expenses and revenues except those directly related to off-system energy sales margins should be removed from Rider 771 as NIPSCO does not have a reasonable need for a rate adjustment mechanism for those expenses and revenues;

- Assuming the aforementioned recommendation is adopted by the Commission: (i) Rider 771 should be renamed "Adjustment for Off-System Sales Margins" and (ii) tracking of MISO Miscellaneous Amount, Revenue Neutrality Uplift and MVP Distribution expenses and revenues should be transferred to NIPSCO's FAC (Rider 770); and

- NIPSCO should be required to absorb 100% of any negative off-system sales margins.

• As detailed in the body of my testimony, NIPSCO's proposed Rider 776 should be modified to:

  - Clarify NIPSCO's adjustment riders do not apply to Back-up Service and Buy-Through Temporary Service;

  - Clarify NIPSCO must confirm all Back-up Service requests that are made in full conformance with Rider 776; and

  - Set the demand charges for Rider 776 by applying the final demand charge percentage increase for Rates 732 and 733 from current Rates 632 and 633 to the current Rider 676 demand charges.

• As detailed in the body of my testimony, NIPSCO's definition of Qualifying Facility in its General Terms and Conditions and is proposed Rider 778 should be modified to be consistent with IC 8-1-2.4-2(g).

• On July 1st of each year, NIPSCO should provide a non-binding, good faith five-year projection of its electric rates under its base rates and riders.

Q DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A Yes, it does.

Qualifications of James R. Dauphinais

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A James R. Dauphinais. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017, USA.

Q PLEASE STATE YOUR OCCUPATION.

A I am a consultant in the field of public utility regulation and a Managing Principal with the firm of Brubaker & Associates, Inc. ("BAI"), energy, economic and regulatory consultants.

Q PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A I graduated from Hartford State Technical College in 1983 with an Associate's Degree in Electrical Engineering Technology. Subsequent to graduation I was employed by the Transmission Planning Department of the Northeast Utilities Service Company[2] as an Engineering Technician.

While employed as an Engineering Technician, I completed undergraduate studies at the University of Hartford. I graduated in 1990 with a Bachelor's Degree in Electrical Engineering. Subsequent to graduation, I was promoted to the position of Associate Engineer. Between 1993 and 1994, I completed graduate level courses in the study of power system transients and power system protection through the Engineering Outreach Program of the University of Idaho. By 1996 I had been promoted to the position of Senior Engineer.

In the employment of the Northeast Utilities Service Company, I was

[2]In 2015, Northeast Utilities changed its name to Eversource Energy.

responsible for conducting thermal, voltage and stability analyses of the Northeast Utilities' transmission system to support planning and operating decisions. This involved the use of load flow, power system stability and production cost computer simulations. It also involved examination of potential solutions to operational and planning problems including, but not limited to, transmission line solutions and the routes that might be utilized by such transmission line solutions. Among the most notable achievements I had in this area include the solution of a transient stability problem near Millstone Nuclear Power Station, and the solution of a small signal (or dynamic) stability problem near Seabrook Nuclear Power Station. In 1993 I was awarded the Chairman's Award, Northeast Utilities' highest employee award, for my work involving stability analysis in the vicinity of Millstone Nuclear Power Station.

From 1990 to 1996, I represented Northeast Utilities on the New England Power Pool Stability Task Force. I also represented Northeast Utilities on several other technical working groups within the New England Power Pool ("NEPOOL") and the Northeast Power Coordinating Council ("NPCC"), including the 1992-1996 New York-New England Transmission Working Group, the Southeastern Massachusetts/Rhode Island Transmission Working Group, the NPCC CPSS-2 Working Group on Extreme Disturbances and the NPCC SS-38 Working Group on Interarea Dynamic Analysis. This latter working group also included participation from a number of ECAR, PJM and VACAR utilities.

From 1990 to 1995, I also acted as an internal consultant to the Nuclear Electrical Engineering Department of Northeast Utilities. This included interactions with the electrical engineering personnel of the Connecticut Yankee, Millstone and Seabrook nuclear generation stations and inspectors from the Nuclear Regulatory Commission ("NRC").

In addition to my technical responsibilities, from 1995 to 1997, I was also responsible for oversight of the day-to-day administration of Northeast Utilities' Open Access Transmission Tariff. This included the creation of Northeast Utilities' pre-FERC Order No. 889 transmission electronic bulletin board and the coordination of Northeast Utilities' transmission tariff filings prior to and after the issuance of Federal Energy Regulatory Commission ("FERC" or "Commission") FERC Order No. 888. I was also responsible for spearheading the implementation of Northeast Utilities' Open Access Same-Time Information System and Northeast Utilities' Standard of Conduct under FERC Order No. 889. During this time I represented Northeast Utilities on the Federal Energy Regulatory Commission's "What" Working Group on Real-Time Information Networks. Later I served as Vice Chairman of the NEPOOL OASIS Working Group and Co-Chair of the Joint Transmission Services Information Network Functional Process Committee. I also served for a brief time on the Electric Power Research Institute facilitated "How" Working Group on OASIS and the North American Electric Reliability Council facilitated Commercial Practices Working Group.

In 1997 I joined the firm of Brubaker & Associates, Inc. The firm includes consultants with backgrounds in accounting, engineering, economics, mathematics, computer science and business. Since my employment with the firm, I have filed or presented testimony before the Federal Energy Regulatory Commission in Consumers Energy Company, Docket No. OA96-77-000, Midwest Independent Transmission System Operator, Inc., Docket No. ER98-1438-000, Montana Power Company, Docket No. ER98-2382-000, Inquiry Concerning the Commission's Policy on Independent System Operators, Docket No. PL98-5-003, SkyGen Energy LLC v. Southern Company Services, Inc., Docket No. EL00-77-000, Alliance Companies, et al., Docket No. EL02-65-000, et al., Entergy Services, Inc., Docket No.

ER01-2201-000, and Remedying Undue Discrimination through Open Access Transmission Service, Standard Electricity Market Design, Docket No. RM01-12-000, Midwest Independent Transmission System Operator, Inc., Docket No. ER10-1791-000, NorthWestern Corporation, Docket No. ER10-1138-001, et al. and Illinois Industrial Energy Consumers v. Midcontinent Independent System Operator, Inc., Docket No. EL15-82-000. I have also filed or presented testimony before the Alberta Utilities Commission, Colorado Public Utilities Commission, Connecticut Department of Public Utility Control, Illinois Commerce Commission, the Indiana Utility Regulatory Commission, the Iowa Utilities Board, the Kentucky Public Service Commission, the Louisiana Public Service Commission, the Michigan Public Service Commission, the Missouri Public Service Commission, the Montana Public Service Commission, the New Mexico Public Regulation Commission, the Council of the City of New Orleans, the Public Utility Commission of Texas, the Wisconsin Public Service Commission and various committees of the Missouri State Legislature. This testimony has been given regarding a wide variety of issues including, but not limited to, ancillary service rates, avoided cost calculations, certification of public convenience and necessity, cost allocation, fuel adjustment clauses, fuel costs, generation interconnection, interruptible rates, market power, market structure, off-system sales, prudency, purchased power costs, resource planning, rate design, retail open access, standby rates, transmission losses, transmission planning and transmission line routing.

I have also participated on behalf of clients in the Southwest Power Pool Congestion Management System Working Group, the Alliance Market Development Advisory Group and several working groups of the Midcontinent Independent System Operator, Inc. ("MISO"), including the Congestion Management Working Group and Supply Adequacy Working Group. I am currently a member of the MISO Advisory

Committee in the end-use customer sector on behalf of a group of industrial end-use customers in Illinois and a group of industrial end-use customers in Texas. I am also the past Chairman of the Issues/Solutions Subgroup of the MISO Revenue Sufficiency Guarantee ("RSG") Task Force.

In 2009, I completed the University of Wisconsin-Madison High Voltage Direct Current ("HVDC") Transmission course for Planners that was sponsored by MISO. I am a member of the Power and Energy Society ("PES") of the Institute of Electrical and Electronics Engineers ("IEEE").

In addition to our main office in St. Louis, the firm also has branch offices in Phoenix, Arizona and Corpus Christi, Texas.

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Energy Price Outlook

Jason Nielsen
Manager – Regulatory Affairs
Alliant Energy – IPL

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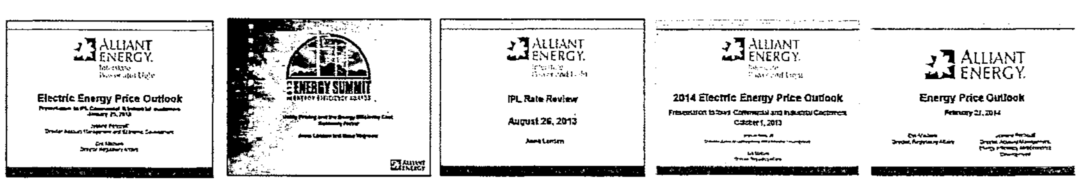
Keeping you informed

- Ongoing pricing outlook webinars since 2011
- Last webinar in October 2015
- Energy Summit May 3, 2016



Tell us what information would be helpful to you.

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Agenda

- Service improvements and customer benefits
- Budgeting guidelines through 2018
- 2017 rate case
- Solutions for your business

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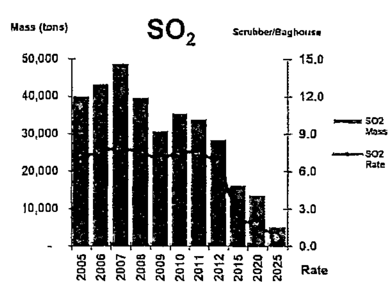
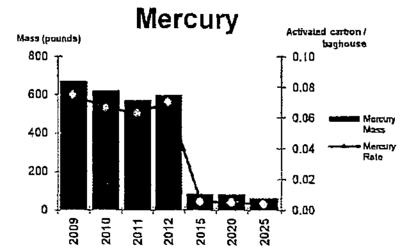
Service improvements and customer benefits

- We are making air cleaner in Iowa
  - From 2011 to 2016, we expect to reduce mercury by 84% and sulfur dioxide by 72%
- We are making the electric grid stronger
  - You have fewer and shorter outages
    - Since 2010, approximately 20% fewer outages and we've shortened the time customers experience an outage by approximately 30%
- New customer information and billing system
- Tax Benefit Rider
  - Customer savings in excess of $400M
- Lower cost nuclear purchased power agreement





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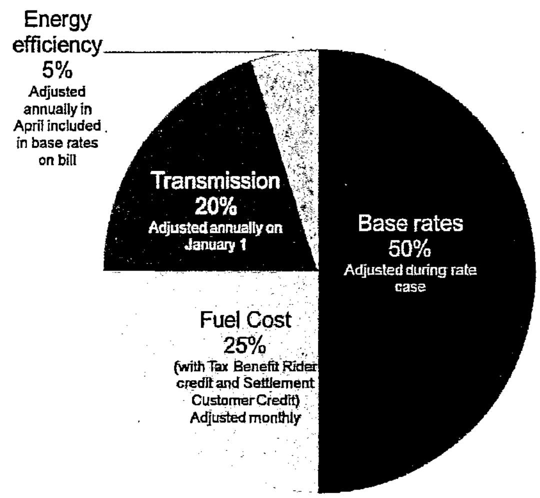
Bill breakdown



**Represents typical Large General Service bill breakdown.*

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Budgeting Guidelines vs. Prior Year

Bill Component	Frequency of Change	2015 Bill Impact	2016 Bill Impact	2017 Bill Impact	2018 Bill Impact
Base Rates	Rate Case	No change	No change	5%	4%
Fuel Cost	Monthly Adjustment	-2%	3%	-1%	0%
Transmission	Annual Adjustment	1%	2%	2%	2%
Tax Benefit Rider	Annual Adjustment	1%	1%	4%	-5%
Customer Credit	Annual Adjustment	3%	1%	0%	0%
Energy Efficiency	Annual Adjustment	No change	No change	No change	No change
Total Bill		3%	7%*	10%*	1%*

*Estimation Range = +/-2% for 2016, +/-3% for 2017 and 2018

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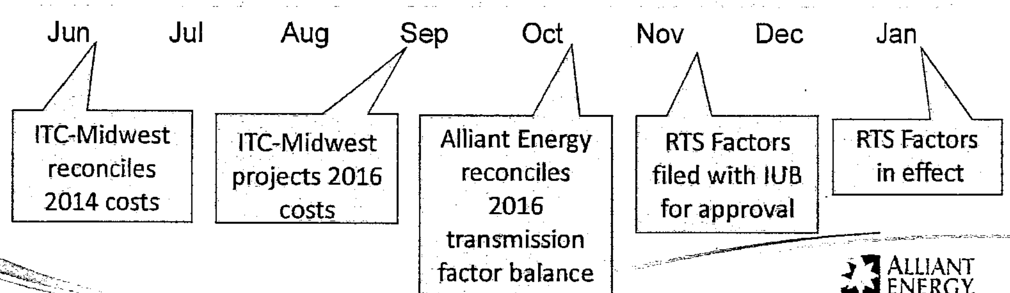
Transmission Rate

- Transmission aka Regional Transmission Service (RTS)
- New factor proposed January 1, 2016

General Service	$0.02579 / kWh	$0.02837 / kWh
Large General Service	$7.40 / kW	$7.99 / kW

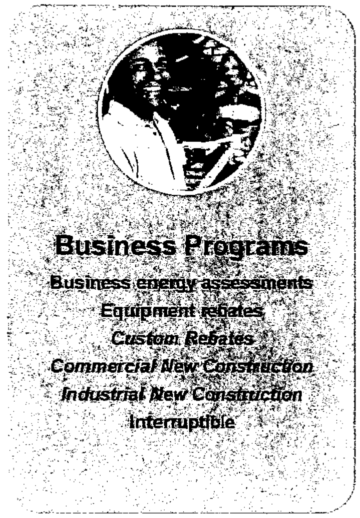


Rate case 2017

- Base rate freeze through 2016
- Timing of filing: April 2017 (estimated)
  - Interim rates effective mid- to late-April 2017
  - Final rates effective in 1Q 2018
- Includes
  - Marshalltown Generating Station
    - 600 MW natural gas plant
    - Approved by IUB/Ratemaking principles
  - Environmental controls / distribution system upgrades
  - New customer information and billing system (2016)
- Identified mitigation measures
  - Lean cost controls
  - Lower costs for MGS transmission interconnection
  - Tax Benefit Rider 2

Solutions for your business

- Energy-saving programs
- Resources
- Sustainability goals
- Energy partner for exploring options



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Who to contact at Alliant Energy?

- Your key account manager
- Business Resource Center
  - 1-866-ALLIANT (866-255-4268), option 2, option 2
    - 8 a.m. to 5 p.m. CST Monday through Friday
  - Email: *businesscenter@alliantenergy.com*
  - Web: *alliantenergy.com/business*
- Link to price schedules at *alliantenergy.com/tariffs*

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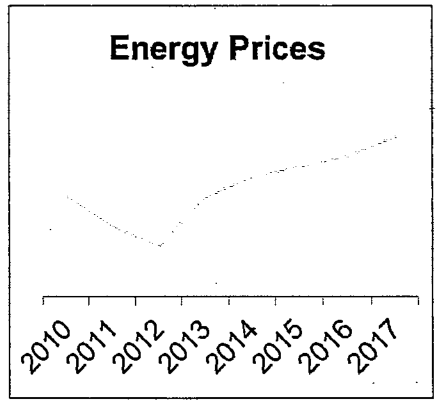
Summary

- Prices are based on costs – driven by service improvements and environmental requirements
- Base rate freeze through 2016
- Budgeting guidelines through 2018
  - Continuing work to mitigate increases
- Energy Summit May 3, 2016



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Questions?

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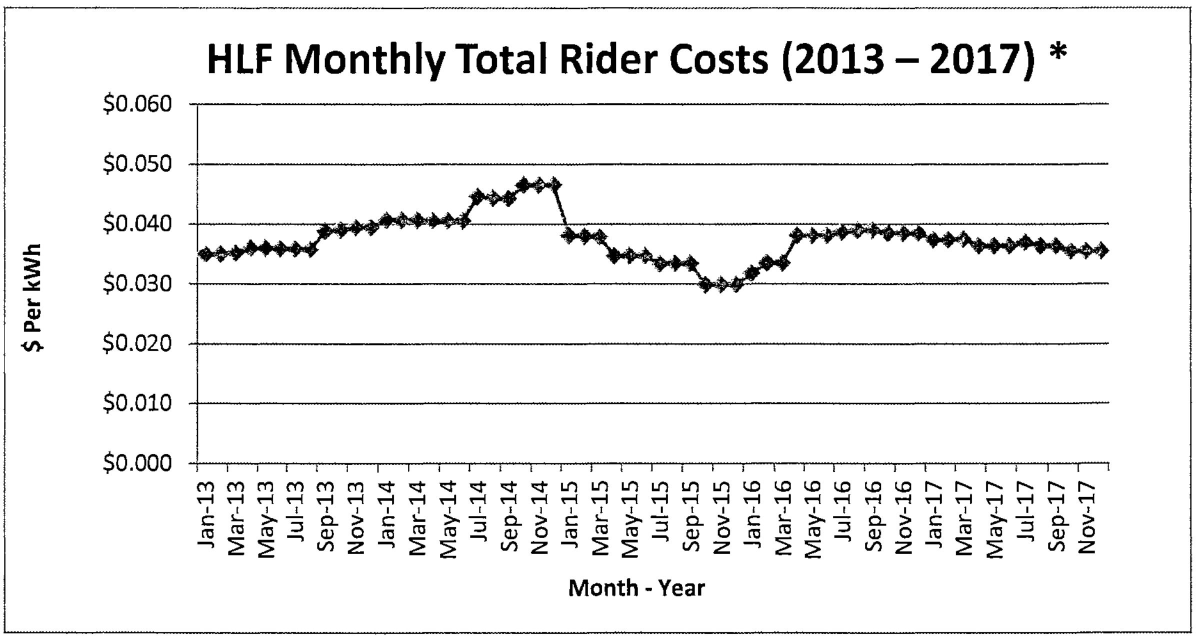
Electric Price Outlook for Indiana High Load Factor (HLF) customers – January 2016

Price projection

Electric prices in 2015 were 9 to14 percent lower than they were in 2014. In 2016, we expect prices to rise slightly, but you'll see in the chart below that rates for Duke Energy Indiana large power customers in 2016 are expected to be close to what they were in 2013. This is primarily due to lower fuel costs, including the impact of a key contract we renegotiated with one of our fuel suppliers.

Depending on your total average cost per kilowatt-hour (kWh), we project our prices for HLF customers to be 3 to 5 percent higher in 2016 compared to 2015. Prices are expected to drop, however, approximately 1 percent in 2017 compared to 2016.



Fuel costs, purchased power costs

The Fuel Adjustment Charge Rider, which includes purchased power costs, is the largest bill rider, comprising an estimated 33 percent of total rider charges for 2016. For HLF customers, this rider is expected to decrease an average of 15 percent in 2016 compared to 2015. We anticipate this rider to continue to decline 17 percent in 2017 compared to 2016.

Although we expect coal prices to remain relatively stable, the following factors can affect prices:

- Deterioration in the financial health of coal suppliers

- Retirements of older coal-fired electric generating units due to more stringent federal environmental regulations
- Declining demand in global markets, which reduces export opportunities
- Continued low natural gas prices and increase in gas supplies
- Increasingly stringent safety regulations for mining operations, which increases costs and lowers production

Indiana grid modernization

In December 2015, we filed a revised $1.83 billion seven-year plan with the Indiana Utility Regulatory Commission to modernize our aging electric grid in Indiana. We revised our proposal based on the commission's guidance, and the new plan is more detailed and focuses on projects that improve the reliability of our service while modernizing our aging infrastructure.

Some of the plan's benefits include:

Improved power reliability and safety from updating and replacing aging electric grid infrastructure, including substations, utility poles, power lines and transformers.

Fewer and shorter power outages where "self-healing" systems are installed. Today, when a tree or other object comes in contact with a power line causing an outage, every customer served by that line – and other lines connected to it – loses power. With self-healing technology, in many cases, we can automatically detect the problem, isolate it and reroute power – so fewer customers are affected while repairs are made.

Faster outage identification because we will be able to send a signal to meters in a targeted area to help identify customers out of service, although we still want customers to call and report any outages. We will also be able to provide you more information about power outages affecting you and more accurate restoration times.

Energy savings from grid technology that optimizes voltage and reduces overall power consumption by about 1 percent on upgraded power lines.

For more information on the plan and its benefits, go to:

duke-energy.com/pdfs/indiana_grid_modernization-whats_changing.pdf

The Indiana Utility Regulatory Commission will hold hearings on the proposed plan, and a decision is anticipated by mid-2016. If the plan is approved by state regulators, you will see a gradual rate increase averaging about 1 percent per year between 2017 and 2022. Estimated rate impacts are reflected in this price communication's projections beginning in 2017.

Edwardsport plant

The Edwardsport IGCC plant began commercial operation in June 2013 and has been serving our Indiana customers using both coal and natural gas.

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The effect of these new regulations will depend on how the state responds to the Clean Power Plan; therefore, it is too early to say what the ultimate rate impact will be.

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In late May, we filed an updated three-year energy efficiency plan for 2016 through 2018 under the provisions of Senate Enrolled Act 412, which was passed by the 2015 Indiana General Assembly. While the three-year plan is similar to the existing energy efficiency programs, two new energy efficiency programs for small commercial and industrial customers have been added: Small Business Energy Saver and Power Manager for Business.

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In Indiana, Duke Energy has rate adjustment riders that have an impact on billings beyond the base rate. The attached table reflects Rate HLF adjustment riders for previous months, as well as changes filed with and pending before the Indiana Utility Regulatory Commission, which are highlighted and marked "filed." Changes marked "projected" have not yet been filed with the commission and reflect projected future filings. These are not approved and may not be approved as filed. The following information is subject to change, depending on the outcome of pending and future commission proceedings.

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Color Code Approved Filed Projected

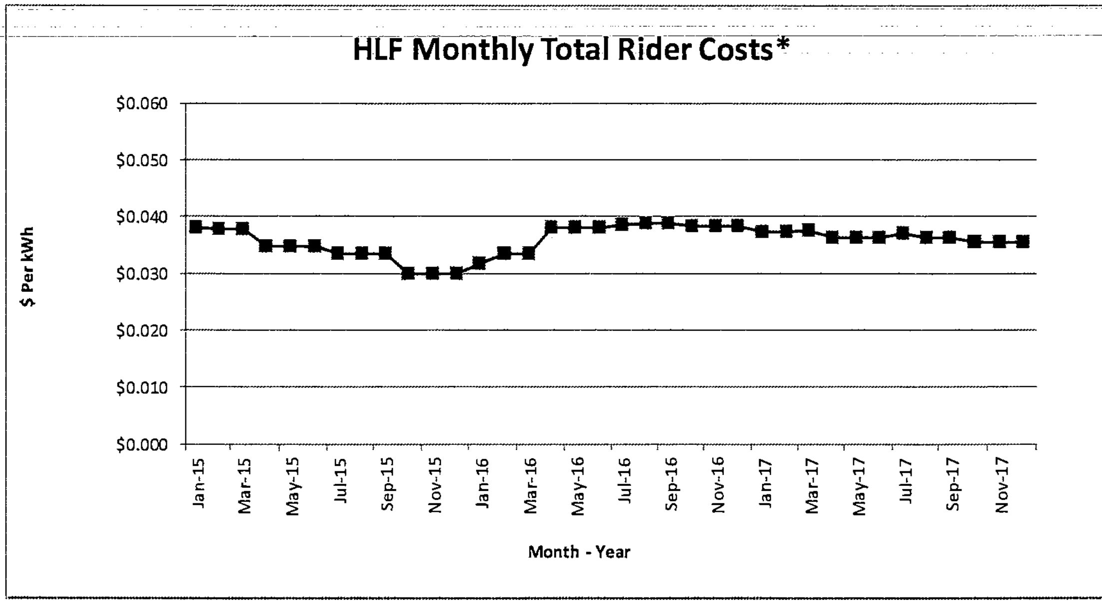
Rate HLF Rider Projections as of January 11, 2016

Month	Quarterly FCR (Fuel) Charge) Rider 60	Annually IGCC Rider 61 See Note (1)	Biannually Qualified Pollution Control (CWIP) Rider 62 See Note (1)	Biannually Emission Allowance Charge Rider 63	Annually Transmission and Distribution Rider 65	Annually Energy Efficiency Rider 66-A	Annually Merger Amortization Credit Rider 67	Quarterly MISO Rider 68	Annually Reliability Rider 70	Biannually Clean Coal Rider 71 See Note (1)	Annually Federally Mandated Costs Rider 72	Total Rider Cost including Energy Efficiency Rider	Total Rider Cost with Energy Efficiency Opt-out See Note (2)
									Actual 2014 Average			**$ 0.043020**	**$ 0.041766**
Jan-15	$ 0.018505	$ 0.010498	$ 0.003023	$ 0.000156		$ 0.000216	$ (0.000334)	$ 0.001345	$ 0.000515	$ 0.004112		$ 0.038036	$ 0.036953
Feb-15	$ 0.018505	$ 0.010498	$ 0.003117	$ 0.000156		$ 0.000216	$ (0.000334)	$ 0.001345	$ 0.000515	$ 0.003916		$ 0.037934	$ 0.036851
Mar-15	$ 0.018505	$ 0.010498	$ 0.003117	$ 0.000077		$ 0.000216	$ (0.000334)	$ 0.001345	$ 0.000515	$ 0.003916		$ 0.037855	$ 0.036772
Apr-15	$ 0.015182	$ 0.010498	$ 0.003117	$ 0.000077		$ 0.000216	$ (0.000334)	$ 0.001460	$ 0.000515	$ 0.003916		$ 0.034647	$ 0.033564
May-15	$ 0.015182	$ 0.010498	$ 0.003117	$ 0.000077		$ 0.000216	$ (0.000334)	$ 0.001460	$ 0.000515	$ 0.003916		$ 0.034647	$ 0.033564
Jun-15	$ 0.015182	$ 0.010498	$ 0.003117	$ 0.000077		$ 0.000218	$ (0.000333)	$ 0.001460	$ 0.000515	$ 0.003916		$ 0.034648	$ 0.033565
Jul-15	$ 0.014188	$ 0.010498	$ 0.003117	$ 0.000077		$ 0.000216	$ (0.000333)	$ 0.001199	$ 0.000500	$ 0.003916		$ 0.033378	$ 0.032295
Aug-15	$ 0.014188	$ 0.010498	$ 0.003218	$ 0.000077		$ 0.000216	$ (0.000333)	$ 0.001199	$ 0.000500	$ 0.003846		$ 0.033409	$ 0.032326
Sep-15	$ 0.014188	$ 0.010498	$ 0.003218	$ 0.000084		$ 0.000216	$ (0.000333)	$ 0.001199	$ 0.000500	$ 0.003846		$ 0.033416	$ 0.032333
Oct-15	$ 0.010285	$ 0.010498	$ 0.003218	$ 0.000084		$ 0.000216	$ (0.000333)	$ 0.001538	$ 0.000500	$ 0.003846		$ 0.029852	$ 0.028769
Nov-15	$ 0.010285	$ 0.010498	$ 0.003218	$ 0.000084		$ 0.000216	$ (0.000333)	$ 0.001538	$ 0.000500	$ 0.003846		$ 0.029852	$ 0.028769
Dec-15	$ 0.010285	$ 0.010498	$ 0.003218	$ 0.000084		$ 0.000216	$ (0.000333)	$ 0.001538	$ 0.000500	$ 0.003846		$ 0.029852	$ 0.028769
									Projected 2015 Average			**$ 0.033961**	**$ 0.032878**
Jan-16	$ 0.010425	$ 0.010498	$ 0.003218	$ 0.000084		$ 0.001843	$ (0.000333)	$ 0.001597	$ 0.000500	$ 0.003846	$ 0.000059	$ 0.031737	$ 0.030226
Feb-16	$ 0.010425	$ 0.010498	$ 0.003224	$ 0.000084		$ 0.001843	$ (0.000333)	$ 0.001597	$ 0.000500	$ 0.005521	$ 0.000059	$ 0.033418	$ 0.031907
Mar-16	$ 0.010425	$ 0.010498	$ 0.003224	$ (0.000036)		$ 0.001843	$ (0.000333)	$ 0.001597	$ 0.000601	$ 0.005521	$ 0.000059	$ 0.033399	$ 0.031888
Apr-16	$ 0.012755	$ 0.012641	$ 0.003224	$ (0.000036)		$ 0.001843	$ (0.000333)	$ 0.001759	$ 0.000601	$ 0.005521	$ 0.000059	$ 0.038034	$ 0.036523
May-16	$ 0.012755	$ 0.012641	$ 0.003224	$ (0.000036)		$ 0.001843	$ (0.000333)	$ 0.001759	$ 0.000601	$ 0.005521	$ 0.000059	$ 0.038034	$ 0.036523
Jun-16	$ 0.012755	$ 0.012641	$ 0.003224	$ (0.000036)		$ 0.001843	$ (0.000324)	$ 0.001759	$ 0.000601	$ 0.005521	$ 0.000059	$ 0.038043	$ 0.036532
Jul-18	$ 0.013496	$ 0.012641	$ 0.003224	$ (0.000036)		$ 0.001843	$ (0.000324)	$ 0.001620	$ 0.000601	$ 0.005521	$ 0.000059	$ 0.038645	$ 0.037134
Aug-16	$ 0.013496	$ 0.012641	$ 0.003155	$ (0.000036)		$ 0.001843	$ (0.000324)	$ 0.001620	$ 0.000601	$ 0.005829	$ 0.000059	$ 0.038884	$ 0.037373
Sep-16	$ 0.013496	$ 0.012641	$ 0.003155	$ 0.000028		$ 0.001843	$ (0.000324)	$ 0.001620	$ 0.000601	$ 0.005829	$ 0.000059	$ 0.038948	$ 0.037437
Oct-16	$ 0.012472	$ 0.012641	$ 0.003155	$ 0.000028		$ 0.001843	$ (0.000324)	$ 0.002120	$ 0.000601	$ 0.005829	$ 0.000059	$ 0.038424	$ 0.036914
Nov-16	$ 0.012472	$ 0.012641	$ 0.003155	$ 0.000028		$ 0.001843	$ (0.000324)	$ 0.002120	$ 0.000601	$ 0.005829	$ 0.000059	$ 0.038424	$ 0.036914
Dec-16	$ 0.012472	$ 0.012641	$ 0.003155	$ 0.000028		$ 0.001843	$ (0.000324)	$ 0.002120	$ 0.000601	$ 0.005829	$ 0.000059	$ 0.038424	$ 0.036914
									Projected 2016 Average			**$ 0.037035**	**$ 0.035524**
Jan-17	$ 0.010401	$ 0.012641	$ 0.003155	$ 0.000028	$ 0.000320	$ 0.002484	$ (0.000324)	$ 0.002089	$ 0.000601	$ 0.005829	$ 0.000107	$ 0.037331	$ 0.035153
Feb-17	$ 0.010401	$ 0.012641	$ 0.002892	$ 0.000028	$ 0.000320	$ 0.002484	$ (0.000324)	$ 0.002089	$ 0.000601	$ 0.006110	$ 0.000107	$ 0.037349	$ 0.035171
Mar-17	$ 0.010401	$ 0.012641	$ 0.002892	$ 0.000024	$ 0.000320	$ 0.002484	$ (0.000324)	$ 0.002089	$ 0.000707	$ 0.006110	$ 0.000107	$ 0.037451	$ 0.035273
Apr-17	$ 0.010083	$ 0.011835	$ 0.002892	$ 0.000024	$ 0.000320	$ 0.002484	$ (0.000324)	$ 0.002112	$ 0.000707	$ 0.006110	$ 0.000107	$ 0.036350	$ 0.034172
May-17	$ 0.010083	$ 0.011835	$ 0.002892	$ 0.000024	$ 0.000320	$ 0.002484	$ (0.000324)	$ 0.002112	$ 0.000707	$ 0.006110	$ 0.000107	$ 0.036350	$ 0.034172
Jun-17	$ 0.010083	$ 0.011835	$ 0.002892	$ 0.000024	$ 0.000320	$ 0.002484	$ (0.000314)	$ 0.002112	$ 0.000707	$ 0.006110	$ 0.000107	$ 0.036360	$ 0.034182
Jul-17	$ 0.010841	$ 0.011835	$ 0.002892	$ 0.000024	$ 0.000320	$ 0.002484	$ (0.000314)	$ 0.001965	$ 0.000707	$ 0.006110	$ 0.000107	$ 0.036971	$ 0.034793
Aug-17	$ 0.010841	$ 0.011835	$ 0.002758	$ 0.000024	$ 0.000320	$ 0.002484	$ (0.000314)	$ 0.001965	$ 0.000707	$ 0.005614	$ 0.000107	$ 0.036341	$ 0.034163
Sep-17	$ 0.010841	$ 0.011835	$ 0.002758	$ 0.000020	$ 0.000320	$ 0.002484	$ (0.000314)	$ 0.001965	$ 0.000707	$ 0.005614	$ 0.000107	$ 0.036337	$ 0.034159
Oct-17	$ 0.009323	$ 0.011835	$ 0.002758	$ 0.000020	$ 0.000320	$ 0.002484	$ (0.000314)	$ 0.002601	$ 0.000707	$ 0.005614	$ 0.000107	$ 0.035455	$ 0.033277
Nov-17	$ 0.009323	$ 0.011835	$ 0.002758	$ 0.000020	$ 0.000320	$ 0.002484	$ (0.000314)	$ 0.002601	$ 0.000707	$ 0.005614	$ 0.000107	$ 0.035455	$ 0.033277
Dec-17	$ 0.009323	$ 0.011835	$ 0.002758	$ 0.000020	$ 0.000320	$ 0.002484	$ (0.000314)	$ 0.002601	$ 0.000707	$ 0.005814	$ 0.000107	$ 0.035455	$ 0.033277
									Projected 2017 Average			**$ 0.036434**	**$ 0.034256**

Note (1): Rider 62 (Qualified Pollution Control), Rider 71 (Clean Coal Operating Cost), Rider 61 (IGCC), Rider 65 (Transmission and Distribution), and Rider 72 (Federally Mandated) for rate group HLF have a demand component based on non-coincident peak demand (kilowatts). For consistency purposes, all of the riders in the HLF table are represented using kilowatt-hours.

Note (2): Represents Total Rider costs for customers who have elected to not participate in energy efficiency programs. Consult with your representative for specific energy efficiency opt-out rates.

Actual and projected total rider costs are represented graphically below.



*Does not include base rates, and includes Energy Efficiency Rider

HLF Annual Rider Impact Estimates

Overview: The following chart shows estimates of the impacts of rate adjustment riders for the HLF Rate. The percent increase estimates comprise actual adjustments, filed adjustments and/or projections of future filings of the HLF rate adjustment riders. Remember that the percent increase estimates are not approved and may not be approved as filed; they are only projections. As previously stated, these projections are subject to change, depending on the outcome of pending and future IURC proceedings and the usage patterns of individual customers.

Instructions: There are two ways to use the projection chart. The first is based on the projected increase in the cost per kilowatt-hour (kWh), and the second on percentage increases in your total average cost per kWh.

Actual Cost per kWh Increase

Step One: The left side of the chart shows actual cost per kWh increases from one budget or projection period to the next. Year-to-year comparisons are provided.

Step Two: Estimate your billed kWh usage for the period for which cost projections are needed, and apply the appropriate cost per kWh increases. Multiply the kWh by the projected increase, and add to your current actuals to determine the estimated cost or budget increase.

Percent Increase in Total Average Cost per kWh

Step One: Determine your average cost per kWh from your electric bill, by dividing "Total Current Electric Charges" by "Billed kWh Usage."

Step Two: Find the number in the "Customer Specific Average Price/kWh" column that is closest to your specific average cost per kWh (as calculated in Step One). Then, use the respective column of the chart to determine the projected increase.

Results: The percent increases represent our best projections for the coming months and years. Please understand that they are only projections and that actual costs will vary. Depending on your forecasted usage, budgeting process and planning requirements, you may need to adjust your final figures up or down to accommodate anticipated events, unforeseen situations or the inherent differences in any forecasting or budgeting process.

Annual Rider Impacts Estimates Based on Average kWh Cost (includes Energy Efficiency Rider)

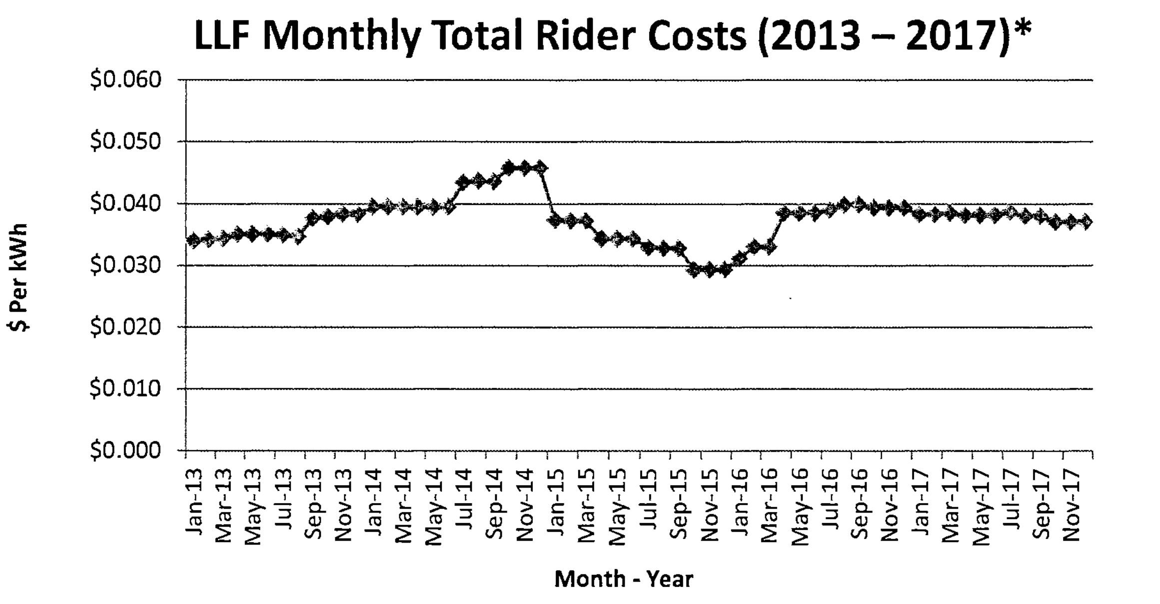
Annual Impacts					
Description	$/kWh	Customer-specific Average Price/kWh	2015 vs 2014	2016 vs 2015	2017 vs 2016
		$0.0650	-13.9%	4.7%	-0.9%
Actual 2015 Rider Average:	$0.033961	$0.0675	-13.4%	4.6%	-0.9%
Actual 2014 Rider Average:	$0.043020	$0.0700	-12.9%	4.4%	-0.9%
Actual 2015 Annual Rider Increase per kWh	**$ (0.009059)**	$0.0725	-12.5%	4.2%	-0.8%
		$0.0750	-12.1%	4.1%	-0.8%
Projected 2016 Rider Average :	$0.037035	$0.0775	-11.7%	4.0%	-0.8%
Actual 2015 Rider Average:	$0.033961	$0.0800	-11.3%	3.8%	-0.8%
Projected 2016 Annual Rider Increase per kwh	**$ 0.003074**	$0.0825	-11.0%	3.7%	-0.7%
		$0.0850	-10.7%	3.6%	-0.7%
Projected 2017 Rider Average :	$0.036434	$0.0875	-10.4%	3.5%	-0.7%
Projected 2016 Rider Average:	$0.037035	$0.0900	-10.1%	3.4%	-0.7%
Projected 2017 Annual Rider Increase per kwh	**$ (0.000601)**	$0.0925	-9.8%	3.3%	-0.6%
		$0.0950	-9.5%	3.2%	-0.6%
		$0.0975	-9.3%	3.2%	-0.6%
		$0.1000	-9.1%	3.1%	-0.6%
		$0.1025	-8.8%	3.0%	-0.6%
		$0.1050	-8.6%	2.9%	-0.6%

Electric Price Outlook for Indiana Low Load Factor (LLF) customers – January 2016

Price projection

Electric prices in 2015 were 8 to 13 percent lower than they were in 2014. In 2016, we expect prices to rise slightly, but you'll see in the chart below that rates for Duke Energy Indiana large power customers in 2016 are expected to be close to what they were in 2013. This is primarily due to lower fuel costs, including the impact of a key contract we renegotiated with one of our fuel suppliers.

Depending on your total average cost per kilowatt-hour (kWh), we project our prices for LLF customers to be 4 to 6 percent higher in 2016 compared to 2015. Prices are expected to increase less than 1 percent in 2017 compared to 2016.



Fuel costs, purchased power costs

The Fuel Adjustment Charge Rider, which includes purchased power costs, is the largest bill rider, comprising an estimated 33 percent of total rider charges for 2016. For LLF customers, this rider is expected to decrease an average of 15 percent in 2016 compared to 2015. We anticipate this rider to continue to decline 17 percent in 2017 compared to 2016.

Although we expect coal prices to remain relatively stable, the following factors can affect prices:

- Deterioration in the financial health of coal suppliers

- Retirements of older coal-fired electric generating units due to more stringent federal environmental regulations
- Declining demand in global markets, which reduces export opportunities
- Continued low natural gas prices and increase in gas supplies
- Increasingly stringent safety regulations for mining operations, which increases costs and lowers production

Indiana grid modernization

In December 2015, we filed a revised $1.83 billion seven-year plan with the Indiana Utility Regulatory Commission to modernize our aging electric grid in Indiana. We revised our proposal based on the commission's guidance, and the new plan is more detailed and focuses on projects that improve the reliability of our service while modernizing our aging infrastructure.

Some of the plan's benefits include:

Improved power reliability and safety from updating and replacing aging electric grid infrastructure, including substations, utility poles, power lines and transformers.

Fewer and shorter power outages where "self-healing" systems are installed. Today, when a tree or other object comes in contact with a power line causing an outage, every customer served by that line – and other lines connected to it – loses power. With self-healing technology, in many cases, we can automatically detect the problem, isolate it and reroute power – so fewer customers are affected while repairs are made.

Faster outage identification because we will be able to send a signal to meters in a targeted area to help identify customers out of service, although we still want customers to call and report any outages. We will also be able to provide you more information about power outages affecting you and more accurate restoration times.

Energy savings from grid technology that optimizes voltage and reduces overall power consumption by about 1 percent on upgraded power lines.

For more information on the plan and its benefits, go to:

duke-energy.com/pdfs/indiana_grid_modernization-whats_changing.pdf

The Indiana Utility Regulatory Commission will hold hearings on the proposed plan, and a decision is anticipated by mid-2016. If the plan is approved by state regulators, you will see a gradual rate increase averaging about 1 percent per year between 2017 and 2022. Estimated rate impacts are reflected in this price communication's projections beginning in 2017.

Edwardsport plant

The Edwardsport IGCC plant began commercial operation in June 2013 and has been serving our Indiana customers using both coal and natural gas.

In September, we reached a settlement agreement related to operating costs at the plant with some of the state's key consumer groups, including the Indiana Office of Utility Consumer Counselor, the Duke Energy Indiana Industrial Group and Nucor Steel-Indiana. If approved by state utility regulators, the settlement limits what you will pay for plant operations, and it will resolve all Edwardsport-related proceedings pending at the commission. There will be regulatory hearings on the settlement, and a commission decision is possible in the first half of 2016.

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Duke Energy Indiana Rider Projections

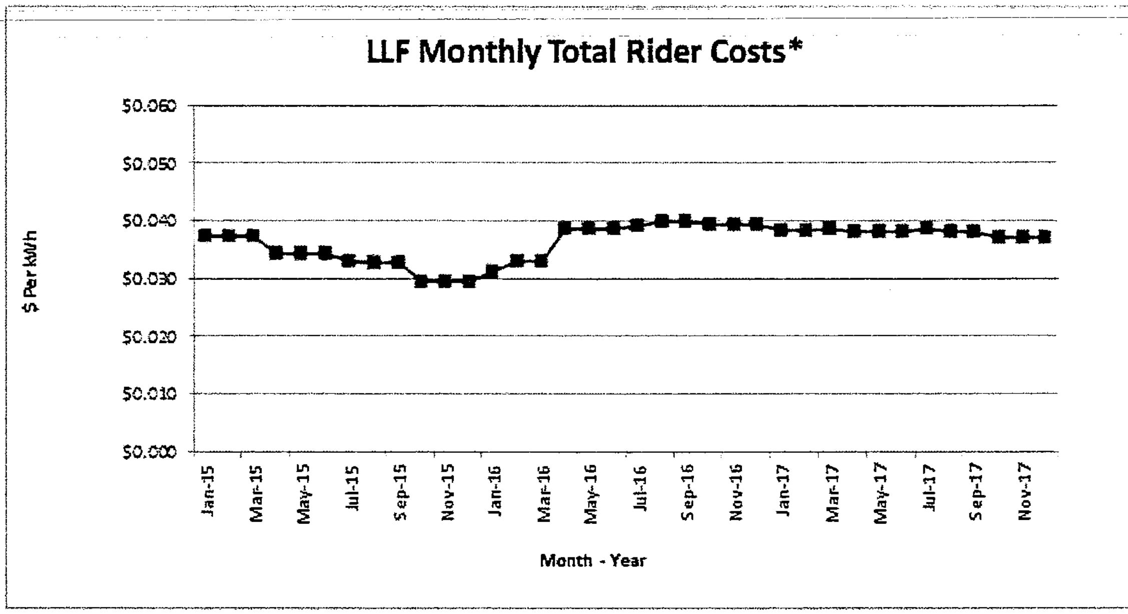
Color Code Approved Filed Projected

Rate LLF Rider Projections as of January 11, 2016

	Quarterly	Annually	Biannually	Biannually	Annually	Annually	Annually	Quarterly	Annually	Biannually	Annually		
Month	FCR (Fuel) Charge) Rider 60	IGCC Rider 61	Qualified Pollution Control (CWIP) Rider 62	Emission Allowance Charge Rider 63	Transmission and Distribution Rider 65	Energy Efficiency Rider 66-A	Merger Amortization Credit Rider 67	MISO Rider 68	Reliability Rider 70	Clean Coal Rider 71	Federally Mandated Costs Rider 72	Total Rider Cost including Energy Efficiency Rider	Total Rider Cost with Energy Efficiency Opt-out See Note
									Actual 2014 Average			**$ 0.042093**	**$ 0.040838**
Jan-15	$ 0.018505	$ 0.010002	$ 0.003089	$ 0.000156		$ 0.000216	$ (0.000342)	$ 0.001066	$ 0.000537	$ 0.004115		$ 0.037344	$ 0.036261
Feb-15	$ 0.018505	$ 0.010002	$ 0.003210	$ 0.000156		$ 0.000216	$ (0.000342)	$ 0.001066	$ 0.000537	$ 0.003936		$ 0.037286	$ 0.036203
Mar-15	$ 0.018505	$ 0.010002	$ 0.003210	$ 0.000077		$ 0.000216	$ (0.000342)	$ 0.001066	$ 0.000537	$ 0.003936		$ 0.037207	$ 0.036124
Apr-15	$ 0.015182	$ 0.010002	$ 0.003210	$ 0.000077		$ 0.000216	$ (0.000342)	$ 0.001473	$ 0.000537	$ 0.003936		$ 0.034291	$ 0.033208
May-15	$ 0.015182	$ 0.010002	$ 0.003210	$ 0.000077		$ 0.000216	$ (0.000342)	$ 0.001473	$ 0.000537	$ 0.003936		$ 0.034291	$ 0.033208
Jun-15	$ 0.015182	$ 0.010002	$ 0.003210	$ 0.000077		$ 0.000216	$ (0.000295)	$ 0.001473	$ 0.000537	$ 0.003936		$ 0.034338	$ 0.033255
Jul-15	$ 0.014188	$ 0.010002	$ 0.003210	$ 0.000077		$ 0.000216	$ (0.000295)	$ 0.001135	$ 0.000464	$ 0.003936		$ 0.032933	$ 0.031850
Aug-15	$ 0.014188	$ 0.010002	$ 0.003217	$ 0.000077		$ 0.000216	$ (0.000295)	$ 0.001135	$ 0.000464	$ 0.003826		$ 0.032830	$ 0.031747
Sep-15	$ 0.014188	$ 0.010002	$ 0.003217	$ 0.000084		$ 0.000216	$ (0.000295)	$ 0.001135	$ 0.000464	$ 0.003826		$ 0.032837	$ 0.031754
Oct-15	$ 0.010285	$ 0.010002	$ 0.003217	$ 0.000084		$ 0.000216	$ (0.000295)	$ 0.001546	$ 0.000464	$ 0.003826		$ 0.029345	$ 0.028262
Nov-15	$ 0.010285	$ 0.010002	$ 0.003217	$ 0.000084		$ 0.000216	$ (0.000295)	$ 0.001546	$ 0.000464	$ 0.003826		$ 0.029345	$ 0.028262
Dec-15	$ 0.010285	$ 0.010002	$ 0.003217	$ 0.000084		$ 0.000216	$ (0.000295)	$ 0.001546	$ 0.000464	$ 0.003826		$ 0.029345	$ 0.028262
									Projected 2015 Average			**$ 0.033449**	**$ 0.032366**
Jan-16	$ 0.010425	$ 0.010002	$ 0.003217	$ 0.000084		$ 0.001843	$ (0.000295)	$ 0.001481	$ 0.000464	$ 0.003826	$ 0.000052	$ 0.031099	$ 0.029588
Feb-16	$ 0.010425	$ 0.010002	$ 0.003325	$ 0.000084		$ 0.001843	$ (0.000295)	$ 0.001481	$ 0.000464	$ 0.005599	$ 0.000052	$ 0.032980	$ 0.031469
Mar-16	$ 0.010425	$ 0.010002	$ 0.003325	$ (0.000036)		$ 0.001843	$ (0.000295)	$ 0.001481	$ 0.000565	$ 0.005599	$ 0.000052	$ 0.032961	$ 0.031450
Apr-16	$ 0.012755	$ 0.013155	$ 0.003325	$ (0.000036)		$ 0.001843	$ (0.000295)	$ 0.001520	$ 0.000565	$ 0.005599	$ 0.000052	$ 0.038483	$ 0.036972
May-16	$ 0.012755	$ 0.013155	$ 0.003325	$ (0.000036)		$ 0.001843	$ (0.000295)	$ 0.001520	$ 0.000565	$ 0.005599	$ 0.000052	$ 0.038483	$ 0.036972
Jun-16	$ 0.012755	$ 0.013155	$ 0.003325	$ (0.000036)		$ 0.001843	$ (0.000332)	$ 0.001520	$ 0.000565	$ 0.005599	$ 0.000052	$ 0.038446	$ 0.036935
Jul-16	$ 0.013496	$ 0.013155	$ 0.003325	$ (0.000036)		$ 0.001843	$ (0.000332)	$ 0.001315	$ 0.000565	$ 0.005599	$ 0.000052	$ 0.038982	$ 0.037471
Aug-16	$ 0.013496	$ 0.013155	$ 0.003335	$ (0.000036)		$ 0.001843	$ (0.000332)	$ 0.001315	$ 0.000565	$ 0.006434	$ 0.000052	$ 0.039827	$ 0.038316
Sep-16	$ 0.013496	$ 0.013155	$ 0.003335	$ 0.000028		$ 0.001843	$ (0.000332)	$ 0.001315	$ 0.000565	$ 0.006434	$ 0.000052	$ 0.039891	$ 0.038380
Oct-16	$ 0.012472	$ 0.013155	$ 0.003335	$ 0.000028		$ 0.001843	$ (0.000332)	$ 0.001783	$ 0.000565	$ 0.006434	$ 0.000052	$ 0.039335	$ 0.037824
Nov-16	$ 0.012472	$ 0.013155	$ 0.003335	$ 0.000028		$ 0.001843	$ (0.000332)	$ 0.001783	$ 0.000565	$ 0.006434	$ 0.000052	$ 0.039335	$ 0.037824
Dec-16	$ 0.012472	$ 0.013155	$ 0.003335	$ 0.000028		$ 0.001843	$ (0.000332)	$ 0.001783	$ 0.000565	$ 0.006434	$ 0.000052	$ 0.039335	$ 0.037824
									Projected 2016 Average			**$ 0.037430**	**$ 0.035919**
Jan-17	$ 0.010401	$ 0.013155	$ 0.003335	$ 0.000028	$ 0.000459	$ 0.002484	$ (0.000332)	$ 0.001631	$ 0.000565	$ 0.006434	$ 0.000097	$ 0.038257	$ 0.036078
Feb-17	$ 0.010401	$ 0.013155	$ 0.003058	$ 0.000028	$ 0.000459	$ 0.002484	$ (0.000332)	$ 0.001631	$ 0.000565	$ 0.006745	$ 0.000097	$ 0.038291	$ 0.036112
Mar-17	$ 0.010401	$ 0.013155	$ 0.003058	$ 0.000024	$ 0.000459	$ 0.002484	$ (0.000332)	$ 0.001631	$ 0.000784	$ 0.006745	$ 0.000097	$ 0.038506	$ 0.036327
Apr-17	$ 0.010083	$ 0.012925	$ 0.003058	$ 0.000024	$ 0.000459	$ 0.002484	$ (0.000332)	$ 0.001817	$ 0.000784	$ 0.006745	$ 0.000097	$ 0.038144	$ 0.035965
May-17	$ 0.010083	$ 0.012925	$ 0.003058	$ 0.000024	$ 0.000459	$ 0.002484	$ (0.000332)	$ 0.001817	$ 0.000784	$ 0.006745	$ 0.000097	$ 0.038144	$ 0.035965
Jun-17	$ 0.010083	$ 0.012925	$ 0.003058	$ 0.000024	$ 0.000459	$ 0.002484	$ (0.000322)	$ 0.001817	$ 0.000784	$ 0.006745	$ 0.000097	$ 0.038154	$ 0.035975
Jul-17	$ 0.010841	$ 0.012925	$ 0.003058	$ 0.000024	$ 0.000459	$ 0.002484	$ (0.000322)	$ 0.001587	$ 0.000784	$ 0.006745	$ 0.000097	$ 0.038682	$ 0.036504
Aug-17	$ 0.010841	$ 0.012925	$ 0.002916	$ 0.000024	$ 0.000459	$ 0.002484	$ (0.000322)	$ 0.001587	$ 0.000784	$ 0.006197	$ 0.000097	$ 0.037992	$ 0.035814
Sep-17	$ 0.010841	$ 0.012925	$ 0.002916	$ 0.000020	$ 0.000459	$ 0.002484	$ (0.000322)	$ 0.001587	$ 0.000784	$ 0.006197	$ 0.000097	$ 0.037988	$ 0.035810
Oct-17	$ 0.009323	$ 0.012925	$ 0.002916	$ 0.000020	$ 0.000459	$ 0.002484	$ (0.000322)	$ 0.002177	$ 0.000784	$ 0.006197	$ 0.000097	$ 0.037060	$ 0.034882
Nov-17	$ 0.009323	$ 0.012925	$ 0.002916	$ 0.000020	$ 0.000459	$ 0.002484	$ (0.000322)	$ 0.002177	$ 0.000784	$ 0.006197	$ 0.000097	$ 0.037060	$ 0.034882
Dec-17	$ 0.009323	$ 0.012925	$ 0.002916	$ 0.000020	$ 0.000459	$ 0.002484	$ (0.000322)	$ 0.002177	$ 0.000784	$ 0.006197	$ 0.000097	$ 0.037060	$ 0.034882
									Projected 2017 Average			**$ 0.037945**	**$ 0.035766**

Note: Represents Total Rider costs for customers who have elected to not participate in energy efficiency programs. Consult with your representative for specific energy efficiency opt-out rates.

Actual and projected total rider costs are represented graphically below.



*Does not include base rates, and includes Energy Efficiency Rider

LLF Annual Rider Impact Estimates

Overview: The following chart shows estimates of the impacts of rate adjustment riders for the LLF Rate. The percent increase estimates comprise actual adjustments, filed adjustments and/or projections of future filings of the LLF rate adjustment riders. Remember that the percent increase estimates are not approved and may not be approved as filed; they are only projections. As previously stated, these projections are subject to change, depending on the outcome of pending and future IURC proceedings and the usage patterns of individual customers.

Instructions: There are two ways to use the projection chart. The first is based on the projected increase in the cost per kilowatt-hour (kWh), and the second on percentage increases in your total average cost per kWh.

Actual Cost per kWh Increase

Step One: The left side of the chart shows actual cost per kWh increases from one budget or projection period to the next. Year-to-year comparisons are provided.

Step Two: Estimate your billed kWh usage for the period for which cost projections are needed, and apply the appropriate cost per kWh increases. Multiply the kWh by the projected increase, and add to your current actuals to determine the estimated cost or budget increase.

Percent Increase in Total Average Cost per kWh

Step One: Determine your average cost per kWh from your electric bill, by dividing "Total Current Electric Charges" by "Billed kWh Usage."

Step Two: Find the number in the "Customer Specific Average Price/kWh" column that is closest to your specific average cost per kWh (as calculated in Step One). Then, use the respective column of the chart to determine the projected increase.

Results: The percent increases represent our best projections for the coming months and years. Please understand that they are only projections and that actual costs will vary. Depending on your forecasted usage, budgeting process and planning requirements, you may need to adjust your final figures up or down to accommodate anticipated events, unforeseen situations or the inherent differences in any forecasting or budgeting process.

Annual Rider Impacts Estimates Based on Average kWh Cost (includes Energy Efficiency Rider)

Annual Impacts					
Description	$/kWh	Customer-specific Average Price/kWh	2015 vs 2014	2016 vs 2015	2017 vs 2016
		$0.0650	-13.3%	6.1%	0.8%
Actual 2015 Rider Average:	$0.033449	$0.0675	-12.8%	5.9%	0.8%
Actual 2014 Rider Average:	$0.042093	$0.0700	-12.3%	5.7%	0.7%
Actual 2015 Annual Rider Increase per kWh	**$ (0.008644)**	$0.0725	-11.9%	5.5%	0.7%
		$0.0750	-11.5%	5.3%	0.7%
Projected 2016 Rider Average :	$0.037430	$0.0775	-11.2%	5.1%	0.7%
Actual 2015 Rider Average:	$0.033449	$0.0800	-10.8%	5.0%	0.6%
Projected 2016 Annual Rider Increase per kwh	**$ 0.003981**	$0.0825	-10.5%	4.8%	0.6%
		$0.0850	-10.2%	4.7%	0.6%
Projected 2017 Rider Average :	$0.037945	$0.0875	-9.9%	4.6%	0.6%
Projected 2016 Rider Average:	$0.037430	$0.0900	-9.6%	4.4%	0.6%
Projected 2017 Annual Rider Increase per kwh	**$ 0.000515**	$0.0925	-9.3%	4.3%	0.6%
		$0.0950	-9.1%	4.2%	0.5%
		$0.0975	-8.9%	4.1%	0.5%
		$0.1000	-8.6%	4.0%	0.5%
		$0.1025	-8.4%	3.9%	0.5%
		$0.1050	-8.2%	3.8%	0.5%

National Regulatory
Research Institute

How Should Regulators View Cost Trackers?

Ken Costello, Principal

National Regulatory Research Institute

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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

[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

[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?

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF NORTHERN INDIANA PUBLIC SERVICE COMPANY FOR AUTHORITY TO MODIFY ITS RATES AND CHARGES FOR ELECTRIC UTILITY SERVICE AND FOR APPROVAL OF: (1) CHANGES TO ITS ELECTRIC SERVICE TARIFF INCLUDING A NEW SCHEDULE OF RATES AND CHARGES AND CHANGES TO THE GENERAL RULES AND REGULATIONS AND CERTAIN RIDERS; (2) REVISED DEPRECIATION ACCRUAL RATES; (3) INCLUSION IN ITS BASIC RATES AND CHARGES OF THE COSTS ASSOCIATED WITH CERTAIN PREVIOUSLY APPROVED QUALIFIED POLLUTION CONTROL PROPERTY, CLEAN COAL TECHNOLOGY, CLEAN ENERGY PROJECTS AND FEDERALLY MANDATED COMPLIANCE PROJECTS; AND (4) ACCOUNTING RELIEF TO ALLOW NIPSCO TO DEFER, AS A REGULATORY ASSET OR LIABILITY, CERTAIN COSTS FOR RECOVERY IN A FUTURE PROCEEDING.	CAUSE NO. 44688

Verification

I, James R. Dauphinais, Consultant and Managing Principal of Brubaker & Associates, Inc., affirm under penalties of perjury that the foregoing representations are true and correct to the best of my knowledge, information and belief.

James R. Dauphinais
1/22/2016