Performance-Based Ratemaking Report

Prepared by
Indiana Utility Regulatory Commission

EXECUTIVE SUMMARY

In 2023, the Indiana General Assembly passed House Enrolled Act 1007, which, among other provisions, tasked the Indiana Utility Regulatory Commission (IURC or Commission) with conducting a comprehensive study on the topic of performance-based ratemaking (PBR) for investor-owned electric public utilities (IOUs).

The study was to include recommendations on the appropriate design, framework, and requirements for effective implementation of PBR mechanisms thought to be appropriate for Indiana.

Through a request-for-proposals contracting process, Christensen Associates Energy Consulting (CA Energy Consulting) was selected to help conduct the study. CA Energy Consulting produced an extensive report and engaged stakeholders to provide both input and feedback into the report.

Commission staff reviewed the report and, pursuant to statute, offers the following recommendations from the report for the General Assembly's consideration:

RECOMMENDATIONS
for the General Assembly's Consideration

1. Enable the Commission to more fully deliver on the policy directives enshrined in the Five Pillars by empowering the Commission to develop, implement, or modify PBR proposals, as guided by policy set by the General Assembly.

2. Require the development of standardized performance metrics for each investor-owned utility to report to the Commission. This would enable more accurate comparative analysis of utility performance and provide a foundation upon which performance incentive mechanisms (PIMs) could be established.

3. Set a timeline for the Commission to implement PIMs, starting with reliability metrics to gain experience on setting goals and determining financial rewards and penalties commensurate with the benefits likely to accrue to customers.

4. Allow more time to understand the full impact and forecasting accuracy of forward test years before considering the implementation of multi-year rate plans.

PERFORMANCE BASED REGULATION

CA Energy Consulting classified two broad categories of PBR tools – multiyear rate plans (MYRPs) and performance incentive mechanisms (PIMs).

MYRPs

MYRPs set rules to adjust rates over the course of the PBR term. MYRP terms are normally for a period of three to five years. Indexed caps in the form of either price or revenue caps work by limiting price or revenue growth to an inflation rate that is adjusted by a measure of industry productivity growth. The intent is to replicate competitive market pressures through a regulatory framework. Indexed caps are more commonly applied to the regulation of distribution-only utilities, and among these cases, the cap sometimes applies only to a limited subset of the utility's total revenues such as operations and maintenance expenses.

Another form of MYRP is a forecasted approach. A forecasted MYRP relies on Commission approved forecasts of utility revenue requirements over a period of three to five years. The forecasted MYRP sets the utility's revenue requirement each year of the PBR term. These forecasts usually include estimates of future operating expenses, capital investments, depreciation, taxes, and the allowed rate of return.

PIMs

PIMs provide financial incentives in the form of either penalties or rewards (or both) to utilities for the production of certain outputs or objectives. Regulators may use PIMs to encourage utilities to direct resources toward achieving specified goals.

PIMs may be appended to traditional regulatory frameworks, such as the regulation of Indiana's IOUs, as the use of PIMs does not require a significant overhaul of the existing regulatory framework. But the development of PIMs that can benefit both the utility and customers requires a thorough stakeholder process and a willingness to adapt as experience is gained.

IMPORTANT FEATURES OF INDIANA'S ELECTRIC UTILITY INDUSTRY AND FORM OF UTILITY REGULATION

CA Energy Consulting emphasized the need to account for important features of Indiana's electric utility industry and the characteristics of utility regulation practiced in Indiana when considering implementation of MYRPs and PIMs.

VERTICAL INTEGRATION AND CAPITAL INVESTMENT

As noted in the CA Energy Consulting report, Indiana utilities are vertically integrated across all three stages of utility operations (generation, transmission, and distribution), which makes the application of a single index MYRP challenging. Capital investment in general, and electric generation in particular, presents a challenge for pure indexed cap PBR. Forecasted MYRPs are more appropriate as this methodology can better account for large ongoing capital investments across the generation, transmission, and distribution stages of providing electric service. The inclusion of capital investments in a forecasted MYRP comes with the risk of limiting the theoretical regulatory advantage of cost control incentives under MYRPs.

USE OF FORWARD TEST YEARS

As noted in the CA Energy Consulting report, Indiana IOUs are permitted to file forward test year revenue requirements in rate cases. A forward-looking test period can be used to set a utility's revenue requirements on the basis of projected data for a 12-month period beginning no later than 24 months after the date on which the utility petitions the Commission for a change in rates. An important feature of the forward-looking test year is the ability to phase in rate increases over two or three steps. As the CA Energy Consulting report notes, this form of cost-of-service regulation using projected data has qualities that overlap with forecasted MYRPs.

An important complement to the use of forward test years is the use of capital investment trackers for pre-approved projects under the Certificate of Public Convenience and Necessity (CPCN) and the Transmission, Distribution, and Storage System Improvement Charge (TDSIC) statutes (IC 8-1-8.5 and IC 8-1-39, respectively), which provide longer timely cost recovery for targeted investments.

PERFORMANCE METRICS REPORTS

Indiana's electric IOUs currently submit annual performance metrics reports covering a broad spectrum of utility performance and operations. These metrics reports were created under Commission directed utility-specific processes that included extensive stakeholder participation. The specific details of the metrics reported are unique to each utility, but all cover measures related to service reliability, workplace safety, generation performance, affordability, operations and maintenance expenses, and customer satisfaction.

The submittal of these reports helps the Commission and stakeholders monitor utility performance across a broad spectrum of operations and service characteristics. Utilities use these and other performance metrics to better understand areas where improvement or investment is needed. Utility regulators and other stakeholders benefit through increased transparency of utility operations.

As CA Energy Consulting notes, PIMs are distinct tools from reported performance metrics. Performance metrics provide useful information while PIMs tie financial rewards and penalties to specific performance metric outcomes.

STAKEHOLDER PERCEPTIONS OF PBR

CA Energy Consulting, with IURC assistance, collected input from Indiana electric utility stakeholders regarding current Indiana regulatory practices, as well as preferences for possible changes. The exercise involved two surveys and a workshop to collect feedback on topics such as MYRPs and PIMs.

As might be expected, opinions varied among the stakeholders on the effectiveness of Indiana's current long-standing and relatively flexible regulatory framework, rate trends, affordability, cost efficiency, and capital investment cycles. Several stakeholders referenced Indiana's Five Pillars (IC 8-1-2-0.6) as a guiding framework.

In survey responses, both utility and other stakeholder groups expressed reluctance to overhaul Indiana's current regulatory framework. Rather, these groups expressed some interest in incremental or optional changes. A common opinion expressed by stakeholders was that the potential of MYRPs and PIMs to provide benefits over the current regulatory processes depends on the complex details to implement these alternative regulatory mechanisms. Among the significant details are varied perspectives on how to define the success of MYRPs and PIMs. Success can be difficult to measure empirically, meaning that there is a significant element of subjectivity to any evaluation of the success of regulatory changes. Also, the complexity of utility operations and the capital-intensive nature of the industry means that the effects of regulatory changes take many years to transpire.

ADMINISTRATIVELY EFFICIENT INCREMENTAL STEPS TO ENHANCE UTILITY PERFORMANCE

REGULATORY CLARITY TO IMPLEMENT PBR

Currently, PBR implementation is limited due to ambiguous authority over whether the Commission can require PBR mechanisms. Under IC 8-1-2.5, IOUs can decide whether to propose a PBR plan. The Commission's options include approving, rejecting, or modifying the plan subject to the utility accepting Commission specified changes. Should the utility reject such changes, it can withdraw its plan.

This legal construction limits the Commission's ability to modify utility proposals to more equitably balance shareholder and ratepayer interests.

RECOMMENDATION 1

Give the Commission clear authority to develop, implement, or modify PBR proposals, guided by criteria set by policymakers. This would provide additional tools for the Commission to deliver on the policy directives enshrined in the five pillars.

PIMs

As noted by CA Energy Consulting, implementation of PIMs has the advantage of being supplemental to Indiana's existing structure of economic regulation. Indiana IOUs already submit to the Commission annual reports providing quantitative metrics covering a broad range of utility operations and performance. The specific details of the metrics reported are unique to each utility, but all cover the same areas of company functions and operations.

RECOMMENDATION 2

Develop standardized IOU performance metric reporting. This requirement benefits stakeholder understanding of comparative utility performance. The current diversity in performance metrics reported by the IOUs makes it impractical in the near term to develop PIMs covering multiple areas of operations and performance. However, the development of PIMs can be done in a phased process starting with reliability performance.

Each electric IOU in Indiana is required to file a reliability report annually with the Commission in compliance with 170 IAC 4-1-23(e). The utilities provide the following three reliability indices in their annual reports to the IURC.

- System Average Interruption Frequency Index (SAIFI): SAIFI is the average number of interruptions per customer. It is calculated by dividing the total number of customer interruptions by the total number of customers.

- System Average Interruption Duration Index (SAIDI): SAIDI is the average minutes of interruption per customer. It is calculated by dividing the sum of all customer interruption durations (in minutes) by the total number of customers.

- Customer Average Interruption Duration Index (CAIDI): CAIDI is the average duration of interruptions or the time to restore service to interrupted customers. It is calculated by dividing SAIDI by SAIFI.

The result is that Indiana has extensive reliability data collected using industry wide standards. Given this circumstance, a timely first step would be to hold a stakeholder process to develop PIMs for reliability. This would align with the criteria recommended by CA Energy Consulting for the design of a PIM, including not rewarding or penalizing the utility for results beyond its control, ensuring that the PIM does not have unintended consequences, and setting financial incentives commensurate with the performance outcomes. The PIM could be considered a pilot aimed at building experience and collecting information about the implementation and efficacy of PIMs as a tool in Indiana.

RECOMMENDATION 3
Implement PIMs starting with reliability metrics to gain experience on setting goals and determining financial rewards and penalties commensurate with the benefits likely to accrue to customers.

With guidance from policymakers, PIMs could be developed for other areas targeting improved service quality and affordability. An “incremental steps roadmap” might include the following steps:

- Begin with implementation of an annual company specific penalty/reward mechanism based on SAIFI/SAIDI. Development of this PIM could help answer questions around the impact of TDSIC investments and vegetation management activities.

- The next step could involve developing a non-fuel operations and maintenance expense metric. This involves a cost category over which utility management has some control, especially over a multi-year period.

- This could be followed by additional cost-based metrics with application of lessons learned in the earlier incremental PIMs development.

The development of reliability PIMs offers Indiana the opportunity to transform its existing performance metric reporting into a framework that provides incentives to utility management to ensure its investments create the expected service improvements to customers while maintaining affordability. Extensive reliability data in a uniform format makes PIM development manageable in a timely manner. The development of other PIMs would require a lengthier and, perhaps, more complicated stakeholder advisory process.

MYRPs

As noted above, the use of forward test years and phased in rate increases in Indiana has common elements with forecasted MYRPs. The rationale behind both the Commission's forward test year and a forecasted MYRP is to provide greater alignment of utility rates with costs. The forward test year approach to setting revenue requirements in Indiana involves a process that is comparable to what would be used to set forecasted revenue requirements over a three to five-year period under a MYRP.

CA Energy Consulting concludes that regulatory guidance regarding forecasted MYRPs should be flexible, allowing each electric IOU to file a tailored MYRP, rather than imposing a common, rigid framework upon each utility.

RECOMMENDATION 4

Implementation of a forecasted MYRP approach in the near term should be rejected. The utilities, Commission, and other stakeholders have relatively little experience with the current application of forward test years. Movement to a multi-year forward revenue requirement would present numerous regulatory process issues and complicated rate setting in an environment characterized by extensive uncertainty. After more experience with forward test years, this topic may be ripe for further evaluation.

GENERAL CONSIDERATIONS FOR PBR IMPLEMENTATION

The electric industry is a capital-intensive industry where infrastructure assets have operational lives measured in decades.

In this context, PBR goals should be long-term to provide utility management and stakeholders appropriate incentives to respond to these changed incentives. The ability to respond to changed incentives might be constrained in the near-term with more opportunities opening over time.

This does not mean the goals and incentive structures are static. Rather, the basic principles and structures should be durable while the specific metrics and incentives evolve in response to continued learning as experience is gained with specific PBR mechanisms.

INDIANA UTILITY REGULATORY COMMISSION
101 W. Washington St., Suite 1500 E.
Indianapolis, IN 46204

317.232.2701 | www.in.gov/IURC

Performance-Based Regulation Report

for
The Indiana Utility Regulatory Commission

By

Nicholas A. Crowley
Daniel McLeod
Corey Goodrich
Andi Romanovs-Malovrh

May 9, 2025

800 University Bay Dr #400
Madison, WI 53705-2299

608.231.2266
www.CAEnergy.com

Table of Contents

EXECUTIVE SUMMARY

This report constitutes the expert study commissioned by the Indiana Utility Regulatory Commission (IURC) to assist with addressing Ind. Code § 8-1-2.5-6.5, which directed the IURC to evaluate the reasonableness of performance-based regulation (PBR) for the state's electricity suppliers. The study addresses Multi-Year Rate Plans (MYRPs) including indexed revenue formulas, and Performance Incentive Mechanisms (PIMs). These are, with minor exceptions, the primary PBR tools used by electric utilities in North America.

PBR encompasses a suite of regulatory mechanisms that may offer utilities enhanced incentives compared to traditional rate-of-return regulation. The two primary categories of PBR tools are MYRPs and PIMs. MYRPs establish rules that adjust rates over the course of the PBR rate term, either through an indexed cap or based on forecasted costs. Under MYRPs, utilities may gain more predictable revenues and may obtain stronger incentives for cost control and innovation. Consumers may benefit from more stable rates, improved utility performance, and the potential for lower rates in the long run as efficiency gains are shared.

PIMs provide incentives for utilities to produce certain outputs through the use of financial rewards and penalties. PIMs can be used to target specific policy objectives like reliability, resiliency, and environmental sustainability.

Although PBR tools may improve utility incentives relative to a given status quo regulatory framework, PBR is not a panacea. The realization of benefits from PBR requires a well-structured design that accounts for the particular circumstances of the jurisdiction or utility. For this reason, while case studies offer valuable insights, we cannot assume that a plan that has been successful for one utility will replicate that success if applied identically elsewhere.

The tools of PBR have been used in other jurisdictions to address policy initiatives similar to Indiana's Five Pillars (reliability, affordability, resiliency, stability and environmental sustainability). However, some differences exist between Indiana and most other jurisdictions that have implemented PBR. First, most utilities that operate with an indexed cap MYRP are distribution-only utilities.[1] Vertically integrated utilities, like the investor-owned utilities (IOUs) in Indiana, generally have larger, lumpier capital investments that may not readily align with an indexed approach to rate regulation. Second, transmission projects for Indiana's IOUs are, to a large degree, directed by the Midcontinent Independent System Operator (MISO). As such, substantial portions of the transmission investments made by Indiana's IOUs are beyond the control of utility management. The participation of Indiana's generation assets in wholesale markets also complicates the prospects of indexed caps, given the interaction of market-based remuneration for energy and an indexed cap. Third, the state's five IOUs each have unique characteristics that may necessitate a tailored PBR approach for each company, potentially limiting uniform application of PBR tools across all utilities. This customization could increase the regulatory burden on the IURC.

[1] See for example, Alberta, Ontario, British Columbia, and Massachusetts.

Multi-Year Rate Plans (MYRPs)

Utility MYRPs consist of several categories: indexed caps, forecast-based rates, and formula rates, though hybrid approaches combining elements of these categories are also common. A hybrid MYRP might blend indexed caps with forecasted revenue adjustments or incorporate other forms of cost-of-service information, like capital trackers.

The design of a MYRP has implications for utility incentives. Whereas indexed caps generally provide enhanced cost efficiency incentives relative to traditional regulation, formula rates have relatively low-cost efficiency incentives and are not considered PBR. Improved cost efficiency incentives may correspond to higher risks to the utility. Or, for utilities with particularly lumpy capital investment, a pure indexed approach may simply not be workable given the utility's spending plan. A well-designed MYRP must balance considerations of cost efficiency with feasibility. If a proposed MYRP framework is out of line with the spending forecast of the utility, it will not provide benefits to customers in the long run, no matter how strong the plan's theoretical incentives might be.

Table ES.1 provides a summary of benefits and challenges of different forms of MYRPs.

Approach	Benefits	Challenges
Price Caps	• Provides an annual rate adjustment equal to the rate of inflation minus industry productivity over the MYRP term • Utility can increase revenue and profits through sales growth • Provides cost efficiency incentives	• May result in intervenor resistance to automatic rate increases not tied to costs • Does not protect the utility against sales declines
Revenue Cap + Decoupling	• Provides an annual rate adjustment equal to the rate of inflation minus industry productivity, plus customer count growth over the MYRP term • Protects utility against sales declines • Provides cost efficiency incentives	• May result in intervenor resistance to automatic revenue increases • Does not allow for revenue increases beyond the I-X+G adjustment, even if sales increases occur
Forecasted MYRP	• Provides utility with opportunity to request revenues according to expected costs • Relatively straightforward to implement • Protects utility against sales declines	• Intervenor resistance to automatic revenue increases • Requires more regulatory scrutiny over spending forecasts • Strength of cost efficiency incentives not well established in economics literature
Formula Rates	• Reduces rate application frequency • Aims to keep revenues and costs closely aligned	• Has the lowest cost efficiency incentives (and is not considered to be PBR) • May face criticism related to the evaluation of projects between rate cases.

Given the industry structure of Indiana's IOUs, we believe that a major overhaul to the regulatory structure may be unnecessarily disruptive. A pure indexed cap approach, which would adjust utility rates or revenues only according to the exogenous factors of inflation and industry productivity, may be infeasible despite the potential cost efficiency benefits. A hybrid approach that excludes capital-intensive components from the indexed cap or that only caps distribution-related revenues may be more suitable for the state's vertically integrated IOUs.

As explained in Table ES.2, forecasted MYRPs may also work as an incremental and optional change from Indiana's existing framework. Regulatory tools currently in place in the state of Indiana, like phased-in rates and forward test years, provide some overlap with this approach. Forecasted MYRPs are more common than indexed caps among vertically integrated utilities.

Table ES.2: Recommendations for MYRPs

Recommendations for MYRPs in Indiana	Given that the top concern among stakeholders relates to affordability and cost control, MYRPs that offer cost efficiency incentives may be worth consideration for Indiana's IOUs. As indexed cap PBR frameworks raise feasibility issues for vertically integrated utilities that operate in Regional Transmission Operator (RTO) regions, we do not recommend pure price caps or revenue caps at this time. Hybrid indexed caps may be feasible on a utility-specific basis, wherein each utility may propose a framework that provides incentives while providing sufficient revenue support over a rate case stay-out period. As such, we recommend allowing IOUs to voluntarily file hybrid PBR plans. Stakeholders also stated that incremental change was preferred to major changes to the state's regulatory framework. Forecasted MYRPs could provide an incremental change that offers improved cost efficiency incentives and reduces rate case frequency. We recommend allowing IOUs to voluntarily file three- or four-year forecasted MYRPs.

Performance Incentive Mechanisms (PIMs)

Utility outputs span more dimensions than just kilowatt-hours of electricity. Output dimensions also include traditional service expectations like reliability, safety, system efficiency (i.e., load factor), connection time, and customer service. Increasingly, outputs also may include environmental policy goals like DER connections, the incorporation of EV charging stations, and energy efficiency. Utilities may not have a direct financial incentive to prioritize some of these traditional and non-traditional outputs. PIMs can offer an economically efficient incentives to achieve Indiana's objectives or remedy output deficiencies by attaching financial rewards or penalties to the achievement of pre-defined standards.

Whereas transitioning from the current cost-of-service regulation framework to an MYRP may entail substantial changes for the utility, stakeholders, and the regulator, PIMs have the advantage of being relatively compatible with existing utility remuneration frameworks.

However, the implementation of PIMs requires careful design to ensure they effectively drive desired outcomes without unintended consequences. Key considerations include selecting metrics that are meaningful, measurable, and within the utility's control; setting achievable targets; and determining the magnitude of financial incentives that will motivate utilities without unduly burdening ratepayers.

While the utilities in Indiana do not operate under PIMs as defined in this section, many of the tools leveraged by the IURC share similar features with target-oriented PIMs. For example, the IURC has in the past made ad-hoc adjustments to utility's allowed ROE during rate cases citing utility performance or management issues as a reason for downward adjustment.[2] In addition, Indiana's DSM initiatives share similarities with PIMs, as Indiana utilities are rewarded for DSM and energy efficiency initiatives that are cost-effective and provide a net benefit to the customers. As well, IOUs obtain a financial incentive for utilities to engage in opportunity sales in the wholesale market that would benefit Indiana customers.

Table ES.3 offers recommendations for PIMs in Indiana.

Table ES.3: Recommendations for PIMs in Indiana

Recommendations for PIMs in Indiana	1. We recommend that the IURC allow the state's IOUs to file PIMs as part of future rate applications, to be assessed on a case-by-case basis. 2. We recommend that before instituting any mandatory PIMs or any PIMs that apply to all utilities, the IURC develop a set of specific policy goals that might be addressed by PIMs and meet with stakeholders to discuss potential benefits and drawbacks of attaching financial incentives to related metrics. Studies may be required to set performance thresholds and the dollar value of financial incentives.

Stakeholder Engagement

Stakeholders, including IOUs, customer groups, and environmental advocates, provided comments on the feasibility of PBR tools in a workshop and in response to two surveys. Based on our findings, there is some openness among stakeholders to pursuing MYRPs, with IOUs expressing tentative interest in exploring an optional approach. One area of relative agreement across groups interested in MYRPs is a preference for revenue caps rather than price caps. The IOUs stated that a revenue cap approach would need to be contingent on the inclusion of specific trackers. Other stakeholders expressed significant concerns about the feasibility and practicality of implementing both indexed cap and forecasted MYRPs in Indiana, citing concerns about impacts on affordability, lack of regulatory oversight, lack of details on a specific Indiana plan, and increased time to validate forecasts.

Stakeholders voiced broader interest in exploring PIMs, although perspectives vary regarding their structure. The overwhelming preference for incremental changes highlights the

[2] Indiana Utility Regulatory Commission, *Cause No. 43526 and Cause No. 44576*. The IURC considered utility performance in selecting the allowed ROE.

stakeholders' preference for a measured approach that builds on the current system rather than introducing sweeping reforms.

Summary of Recommendations

The tables below comprise other recommendations presented in this report. Many of our recommendations are conditional, rather than absolute, highlighting best practices and nuances of implementing certain PBR tools.

Table ES.4: Summary of Guiding PBR Principle Recommendations

Guiding Principles of PBR	1. The IURC should adopt a set of principles associated with incentive regulation. 2. The development of guiding principles should involve some consensus from utility stakeholders. 3. The IURC may wish to draw from the five principles set forth in this Section 4.5 as a starting point in the development of the state's principles.

Table ES.5: Summary of Revenue Decoupling Recommendations

Revenue Decoupling	Indiana's IOUs already operate with a Lost Revenue Adjustment Mechanism (LRAM), which shares some properties with revenue decoupling mechanisms. If stakeholders agree that the LRAM is reasonable, we recommend maintaining this approach with no changes.

Table ES.6: Summary of Indexed Cap Recommendations

Indexed Caps	Price or revenue caps may be of interest in Indiana because of the potential to improve cost efficiency among the state's IOUs. However, the vertically integrated organization of the state's electric utilities presents practical complications. If the state pursues indexed caps, we recommend a hybrid approach as follows: • Only the distribution portions of utility operations operate under the indexed cap; and/or • Capital costs should be either forecast or tracked by a company-specific mechanism; We also recommend adopting the recommendations in Sections 5.1.5.1 through 5.1.5.7.
Indexed Cap Inflation Factors	If the state of Indiana adopts an indexed cap approach to PBR or a hybrid approach that places some portion of revenue under a cap, we recommend that an inflation factor be included in the

	PBR formula (I-X). The inflation factor should be established to reflect the electric utility sector’s annual input price growth. If an output price measure of inflation is used, the X factor must be adjusted accordingly.
Indexed Cap X Factors	If the state of Indiana adopts an indexed cap approach to PBR or a hybrid approach that places some portion of revenue under a cap, we recommend that an X factor be included in the PBR formula (I-X). This X factor should be calculated from an industry TFP growth or Kahn Methodology analysis.
Indexed Cap Stretch Factors	If the state of Indiana adopts an indexed cap approach to PBR or a hybrid approach that places some portion of revenue under a cap, we recommend that a stretch factor be included in the formula (I-X-S). This stretch factor should be company-specific based on industry cost benchmarking analysis.
Z Factors	If the state of Indiana adopts an indexed cap or forecasted MYRP approach to PBR or a hybrid approach that places some portion of revenue under a cap, we recommend that a Z factor be included in the PBR framework. The Z factor should be company-specific and have a materiality threshold roughly in line with thresholds seen in other jurisdictions.
Y Factors	If the state of Indiana adopts an indexed cap or forecasted MYRP approach to PBR or a hybrid approach that places some portion of revenue under a cap, we recommend that a Y factor be included in the PBR framework. The Y factor should be company-specific and the costs eligible for Y factor treatment should be clearly defined at the outset of the PBR term.
Capital Factors	If the state of Indiana adopts an indexed cap regulatory framework, we recommend that some form of capital supplement be included on an as-needed basis. The capital factor should be company-specific and the costs eligible for capital factor treatment should be clearly defined at the outset of the PBR term. Economic principles and the guidelines of PBR should be considered in the design of the capital factor.
Reopeners	If the state of Indiana adopts an indexed cap regulatory framework or a forecasted MYRP, we recommend that some form of reopener be included. The reopener provision should be clearly defined, with a clear description of how it would be applied in the event of being triggered.
Earnings Sharing Mechanisms	If the state of Indiana adopts an indexed cap regulatory framework (or a forecasted MYRP), utilities or utility stakeholders may wish to incorporate ESMs to reduce risk.

	However, if ESMs are adopted, we recommend wide deadbands in order to maintain cost efficiency incentives.
Efficiency Carryover Mechanisms	If the state of Indiana adopts an indexed cap regulatory framework (or a forecasted MYRP), we recommend exploring Efficiency Carryover Mechanisms as a way to maintain cost efficiency incentives over rebasing periods.

Table ES.7: Summary of Forecasted MYRP Recommendations

Forecasted MYRPs	Forecasted MYRPs may be a feasible incremental step toward PBR for Indiana because of the overlap of this kind of framework with current ratemaking practices in the state. Forward test years and phase-in rates are already approved for Indiana's IOUs, and these mechanisms have much in common with forecasted MYRPs. If done correctly, forecasted MYRPs have the potential to improve utility cost efficiency incentives and reduce the regulatory burden of frequent rate cases. If the state pursues forecasted MYRPs, we recommend: • Allow the IOUs to file tailored MYRPs, rather than imposing a common, rigid framework upon each utility. • Forecasted MYRPs may include elements discussed in Section 5.1, regarding indexed caps. For example, exogenous cost factors (Z and Y factors) may be included, as well as reopener provisions or ESMs.

Table ES.8: Summary of Formula Rate Plan Recommendations

Formula Rate Plans	We do not currently recommend Indiana to pursue formula rate plans. However, if IOUs face major, lumpy investments and the frequency of rate cases becomes a problem, this is an option that could be considered.

1 INTRODUCTION

1.1 Background and Scope of Work

This report constitutes the expert study commissioned by the Indiana Utility Regulatory Commission (IURC) to assist with addressing Ind. Code § 8-1-2.5-6.5, which directed the IURC to evaluate the reasonableness of performance-based regulation (PBR) for the state's electricity suppliers. The study addresses Multi-Year Rate Plans (MYRPs) including indexed revenue formulas, and Performance Incentive Mechanisms (PIMs). These are, with minor exceptions, the primary PBR tools used by electric utilities in North America.

The purpose of the study is to evaluate the PBR tools that may be used to regulate investor-owned electric utilities (IOUs) in the state of Indiana. To achieve this, the report will include a review of PBR tools and methods used in other jurisdictions, a discussion of related economic theory, results from engagement with stakeholders in the state of Indiana, feedback from regulators in other jurisdictions, hypothetical PBR scenarios, and recommendations related to PBR for regulated electricity suppliers in the state. The report will also discuss best practices for allocating the costs, benefits, and risks associated with PBR between customers and shareholders, as well as best practices for establishing utility performance metrics.

The organization of the report is as follows. This section of the report provides our research context, including the statute directing this study passed by the Indiana General Assembly. Section 2 explains fundamental concepts of rate regulation, comparing and contrasting traditional regulation with PBR. Section 3 provides an overview of Indiana's current regulatory framework. Sections 4 through 7 present a description of typical PBR mechanisms, including discussions of the economic principles supporting each tool and a review of jurisdictions where those tools are currently in place. Section 8 contains the findings from engagement with stakeholders, which has taken the form of surveys and workshops. Section 9 contains hypothetical scenarios that illustrate how PBR mechanisms might be applied to the investor-owned utilities in Indiana. Section 10 concludes with a summary of findings and our recommendations.

1.2 Indiana Code § 8-1-2.5-6.5

The statute passed by the General Assembly, which prompted the development of this report, is provided in full below. This report addresses the requirements set forth in the General Assembly's language. Throughout the report, we cite this statute language, particularly from part (c), which outlines the research requirements of the report. Section 8 of the report, which provides stakeholder feedback, responds to the requirements set forth in part (d).

The Full Text of Indiana Code § 8-1-2.5-6.5

Sec. 6.5. (a) As used in this section, "electricity supplier" means a public utility (as defined in IC 8-1-2-1(a)) that furnishes retail electric service to customers in Indiana. The term does not include a utility that is:

(1) a municipally owned utility (as defined in IC 8-1-2-1(h));
(2) a corporation organized under IC 8-1-13; or
(3) a corporation organized under IC 23-17 that is an electric cooperative and that has at least one (1) member that is a corporation organized under IC 8-1-13.

(b) Before September 1, 2023, the commission shall commence a comprehensive study to consider the appropriate:

(1) design and framework for; and
(2) requirements with respect to;

performance based ratemaking (as described in section 6(a)(2) of this chapter) for electricity suppliers.

(c) In conducting the study required by this section, the commission shall evaluate the following:

(1) Multi-year rate plans with incremental rate increases.
(2) Index-driven revenue formulas.
(3) Performance incentive mechanisms, including both rewards and penalties, for meeting, or failing to meet, metrics related to service or infrastructure investments.
(4) The use of performance incentive mechanisms in conjunction with traditional cost-of-service ratemaking, to provide regulatory oversight and ensure that rewards and penalties are equitably balanced and do not:
(A) over-compensate electricity suppliers for benefits provided; or
(B) under-compensate electricity suppliers for costs and risks incurred;
as applicable.
(5) Best practices for allocating the costs, benefits, and risks associated with performance incentive mechanisms between:
(A) customers and customer classes; and
(B) shareholders;
with affordability of service prioritized.
(6) Best practices for establishing quantifiable, verifiable, and clearly defined performance metrics in connection with performance incentive mechanisms.
(7) Best practices for the collection and protection of data from electricity suppliers as needed to justify or evaluate proposed or approved performance incentive mechanisms.
(8) Any other aspect of performance based ratemaking that the commission determines to be appropriate to incentivize electricity suppliers to provide value to ratepayers.

(d) In conducting the study required by this section, the commission may invite comments from:

(1) electricity suppliers;
(2) the office of utility consumer counselor;
(3) associations or organizations representing utility ratepayers;
(4) regulatory commissions or agencies in other states that have experience with performance based ratemaking;
(5) rate design experts; or

(6) other stakeholders.

The commission may incorporate any comments received under this subsection in its report under subsection (e).

(e) The commission shall include in the annual report that the commission is required to submit under IC 8-1-1-14 before October 1, 2025, a report that includes the commission's analysis and recommendations on the topics outlined in subsection (c). The report required by this subsection must contain recommendations, supported by sufficient data and analysis from the commission's study under this section, with respect to the appropriate:

(1) design and framework for; and
(2) requirements with respect to;

performance based ratemaking (as described in section 6(a)(2) of this chapter) for electricity suppliers, so as to enable the general assembly to fully evaluate the impact of performance based ratemaking on all classes of ratepayers, while considering the attributes of electric utility service set forth in IC 8-1-2-0.6, including reliability, affordability, resiliency, stability, and environmental sustainability.

1.3 How to Use this Report

Readers of this report may have a variety of backgrounds. We expect that readers who have familiarity with the utility industry could include regulatory staff, utility managers, researchers, and consultants. For these readers, we hope to convey details on terms and tools in use in the regulated utility sector, as well as information about the current state of PBR in North America. Other readers may have less knowledge about the mechanics of utility regulation. These readers may include policymakers and their staff. Our aim is to convey foundational information to these readers regarding the way utilities are currently regulated in Indiana, the opinions of stakeholders on key regulatory issues, possible improvements to the status quo, and why these improvements might be effective.

For readers with substantial background in utility regulation, particularly with respect to incentive regulation, it may be useful to skip around to sections that are of particular interest. For others, we have structured the report so that each section builds on previous sections. This means that reading the report sequentially makes sense for readers less familiar with the industry, as we begin with the fundamentals of regulation.

In some sections of the report, we provide recommendations. Many of these recommendations are conditional, rather than absolute. For example, we provide a number of recommendations for how to design an indexed cap PBR framework, conditional on the state of Indiana deciding to pursue such a framework. The aim is to provide an understanding of best practices. We also provide some recommendations about potential incremental changes policymakers might consider for regulation in the state of Indiana. Section 10 contains a complete summary of our recommendations.

2 FUNDAMENTALS OF RATE REGULATION

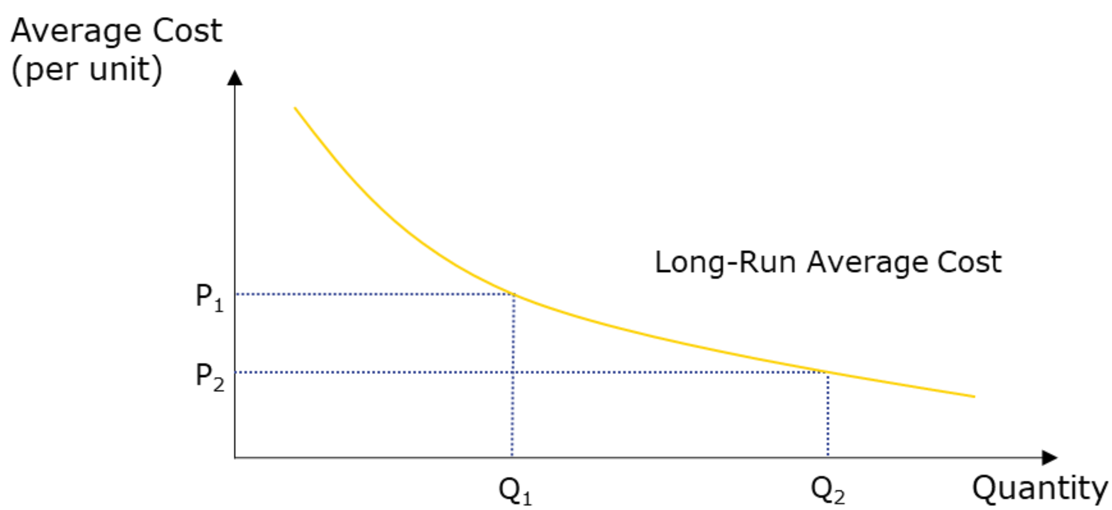
2.1 Electricity Industry Basics

Electric utilities own and operate high voltage transmission lines and distribution lines that connect end users to the grid.[3] In Indiana, investor-owned utilities also own and operate power generation facilities (i.e., power plants).

The infrastructure required to generate, transmit, and distribute electricity involves substantial upfront investments. This makes duplicative service providers uneconomical. Thus, in most jurisdictions, utilities are granted exclusive rights to serve a specific geographic area. These exclusive rights are paired with a requirement to serve all customers within their service area, along with regulatory oversight that sets prices and monitors service quality.

Established models of so-called "natural monopolies"—industries most efficiently organized under a single producer—justify the regulatory agreement of a single, regulated electricity provider in a given service territory. These models note that the electric utility industry's high fixed costs result in declining long-run average costs as the scale of production increases.[4] Fixed costs in the form of substantial infrastructure investments and capital equipment remain relatively constant regardless of power production volumes. When these fixed costs are spread across a larger output, the average cost per unit decreases (see Figure 2.1). This phenomenon indicates that electric utilities experience economies of scale.

Figure 2.1: Declining Long-Run Average Cost and Economies of Scale[5]



[3] Transmission lines are a system of structures, wires, insulators, and associated hardware that carry electric energy at high voltages across long distances. Distribution lines are wires and other infrastructure that move electricity from the transmission line to end users' service lines (for example, in neighborhoods).

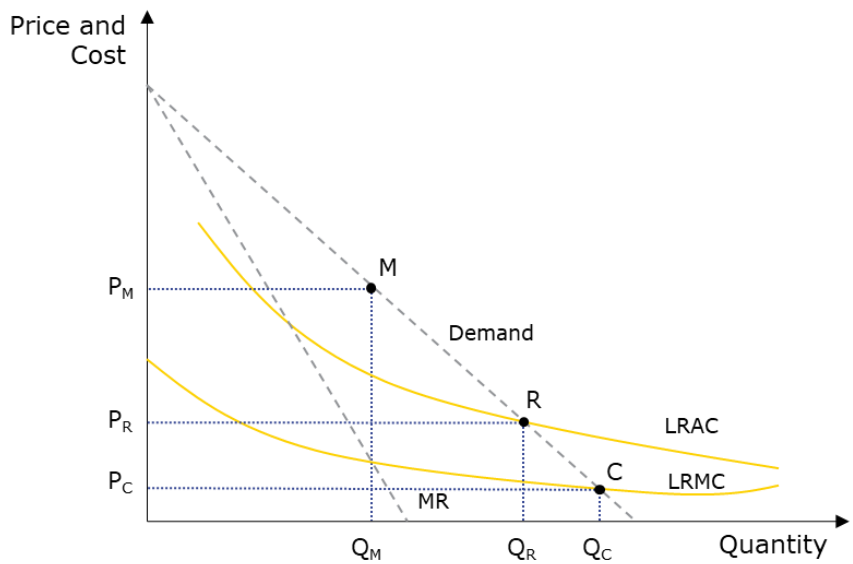
[4] Phillips, Charles Franklin. The Regulation of Public Utilities: Theory and Practice. United States: Public Utilities Reports, 1988.

[5] With long-run average costs that decline as the quantity produced increases, the total cost to provide quantity Q_2 at price P_2 by a single firm is lower than the cost to provide the same quantity Q_2 by two firms at price P_1.

In the absence of competitive forces or regulation, a utility would have the ability to exert control over pricing. This would be expected to lead to suboptimal market outcomes, reducing the total economic surplus that would be expected in a more competitive environment. It would also be unfair for consumers. One of the key directives of the regulator, therefore, is to set rates close to the efficient market outcome while allowing the utility to recover its fixed costs.

Figure 2.2 provides a simplified model of rate-setting in a regulated environment. The model assumes a utility's long-run average cost (LRAC) declines with increases in production quantity. Absent regulation, the firm would set the price to maximize profit, which happens when long run marginal cost (LRMC) equals marginal revenue (MR). In the figure, this is achieved at point M on the demand curve and results in a price P_M. In a perfectly competitive market, on the other hand, the price would be equal to the LRMC (point C on the demand curve with price P_C). However, this price would not provide sufficient revenue to cover fixed costs and would therefore result in a financial loss. A regulatory solution is to set the price according to where the demand curve intersects LRAC (point R on the demand curve with price P_R). This moves the price closer to an efficient price than a monopolist would set under no regulation while providing the utility with the opportunity to recover its fixed costs. Embedded cost-of-service regulation sets rates according to this approach.

Figure 2.2: Natural Monopoly in a Regulated Pricing Environment[6]



A second key objective of the regulator is to ensure the utilities meet a high standard of electricity service quality. This objective has long been recognized as a challenge, as the means of service quality regulation are less straightforward.[7] Methods of regulating service quality include tracking metrics, recording customer complaints, and undertaking inspections.

This report recognizes that Indiana's current approach to rate and service quality regulation align closely with other jurisdictions in North America.

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[6] For further discussion, see, for example, *Optimal Regulation: The Economic Theory of Natural Monopoly*, Kenneth E. Train, 1994, p. 16.

[7] *The Economics of Regulation,* Alfred Kahn, 1970, p. 22.

2.2 Traditional Cost of Service Regulation

2.2.1 Why Regulate Under Cost-of-Service Regulation

Investor-owned utilities across North America face regulatory oversight vis-à-vis revenue recovery. Electric utilities and other network firms have traditionally operated under "cost-of-service regulation" (COSR), also known as "rate-of-return" regulation, under which firms submit an accounting of annual costs (i.e., revenue requirement) in periodic rate filings before their regulatory authority for approval. Rates are then set to recover approved costs. Such an approach carries both benefits and drawbacks.

As described in Section 2.1, utility regulation exists primarily because electric utilities, particularly transmission and distribution network operations, face limited competitive market pressures. These industries have high fixed costs and significant economies of scale that make competition impractical or inefficient. Regulation serves as a substitute for market competition by protecting consumers from the price implications of this market power while ensuring reliable service and adequate infrastructure investment. Regulatory frameworks aim to balance the public interest with reasonable returns for utility shareholders, while addressing externalities and public policy objectives that markets might not adequately account for on their own.

2.2.2 The Mechanics of Cost-of-Service Regulation

Utilities are regulated through a formal rate application process commonly referred to as the "rate case".[8] A rate case is a formal regulatory proceeding where a utility requests approval to change its rates. The process typically begins with the filing of the utility's proposal with supporting documentation, followed by discovery and information exchange between parties. Public hearings provide opportunities for stakeholder input, while expert testimony and cross-examination help establish the factual record. After deliberation, the regulatory commission issues a final decision. These proceedings serve as the primary way for determining what costs are prudent and reasonable for recovery through customer rates, establishing the balance between utility financial health and consumer protection.

A key component of rate cases is the revenue requirement, which serves as the basis for determining rates charged to customers. The revenue requirement in COSR consists of several key components. The formula is often expressed as:

$$\begin{aligned} &\mathit{Revenue\ Requirement} \\ &\quad = \mathit{Operating\ \&\ Maintenance\ Expenses} + \mathit{Depreciation\ and\ Amortization} \\ &\quad + \mathit{Taxes} + (\mathit{Rate\ Base} * \mathit{Rate\ of\ Return}) \end{aligned} \tag{2.1}$$

Operating expenses include labor, materials, services, and fuel costs necessary to provide service, along with other approved costs such as those required to facilitate demand-side management programs. Taxes include income and property taxes. The rate base for an electric utility represents the total book value of the company's assets that are considered used and useful in providing electricity service to its customers. Rate base equals a utility's gross plant in

[8] While "rate case" is the commonly used term in the United States, the name of the process can differ in other jurisdictions. For example, rate cases are called rate determinations in Australia and price control review in the United Kingdom.

service, minus accumulated depreciation, with adjustments for working capital and other, smaller components. Return on rate base allows utilities to earn their authorized rate of return on invested capital. The revenue requirement also includes capital depreciation and amortization expenses. This approach, relying on historical embedded costs, aims to allow utilities the opportunity to maintain financial viability in the provision of essential services.

Through a rate case, the regulator and other intervenors interrogate the utility's revenue requirement. This includes assessing incurred expenditures, capital depreciation rates, customer class cost allocation, customer rate designs, and the allowed rate of return on rate base. The allowed rate of return can be a particularly contentious issue, as it reflects the portion of revenue requirement attributable to accounting profit.

Utilities may also request alternative revenue recovery mechanisms, like cost trackers, that may be approved through a rate case process. Capital trackers are a common form of cost tracker, often applying to capital investments that meet certain criteria. Trackers provide annual revenue recovery for necessary investments, reducing regulatory lag. This can provide utilities with assurance of cost recovery for major projects between rate cases.

2.2.3 Incentives Under Cost-of-Service Regulation

COSR has several important implications for both utilities and consumers. Under traditional COSR, utilities may recover prudently incurred costs. This provides a degree of regulatory certainty required to undertake for long term, capital-intensive investments. COSR also operates such that customers only pay rates for costs incurred prudently. However, COSR also has well-known limitations. Relying on a historical test year to set rates can mean a utility's revenue growth persistently lags its growth in costs. The COSR model also delivers limited incentives for cost efficiency since cost increases can be recovered through rate cases timed at the discretion of the utility. Furthermore, these regulatory proceedings can be resource intensive, which is especially costly in an inflationary environment, wherein utilities must file rate applications with greater frequency.

In most jurisdictions, utility management determines when to file rate applications. While rate case frequency varies considerably across regulatory landscapes, recent years have seen an uptick in filings, primarily driven by mounting capital investment needs and persistent inflationary pressures.[9] Recognizing the substantial administrative burden these proceedings place on both utilities and regulators, many jurisdictions have implemented limited adjustment mechanisms that allow for targeted cost recovery between comprehensive rate cases, creating a more flexible regulatory approach while maintaining appropriate oversight.

An alternative approach, commonly called either incentive regulation or PBR, aims to mitigate the shortcomings of traditional COSR by providing superior economic efficiency incentives and administrative savings. This alternative form of rate regulation has a decades-long history across multiple industries, including telecommunications, railroads, postal services, and oil transmission pipelines, as well as gas and electric distribution utilities.

[9] Lowrey, Dan. "Rate Requests by US Energy Utilities Set Record in 2023 for 3rd Straight Year." S&P Global Market Intelligence, February 7, 2024.

2.3 A Brief Overview of Performance-Based Regulation (PBR) Tools

In recent years, various forms of performance-based regulation (PBR) have increasingly drawn the attention of regulators and utilities as a potential means of improving electricity and gas utility efficiencies and reducing regulatory costs.

One category of PBR tools, known as Multi-Year Rate Plans (MYRPs), establish rules to adjust rates over the course of the PBR rate term.[10] Indexed caps in the form of either a price or revenue caps work by limiting price or revenue growth to an inflation rate that is adjusted by a measure of industry productivity growth, thereby introducing competitive market pressures into a market that is largely considered to be dominated by non-competitive firms.[11] At the same time, the cap provides relief from earnings attrition over time by allowing rates to increase by a simple formula and is therefore sometimes called an attrition relief mechanism (ARM). In some cases, the indexed cap applies to a subset of total revenues, rather than the entire company's revenue requirement. Indexed cap plans that apply to a subset of total revenues are sometimes called "hybrid ARMs."

A second set of PBR tools, known as Performance Incentive Mechanisms (PIMs), provide incentives for utilities to produce certain outputs. Regulators may impose PIMs to encourage utilities to direct resources toward achieving certain goals that are not likely to be achieved under traditional regulatory frameworks. PIMs may be more easily added to existing utility remuneration models than indexed caps, as they do not require an overhaul of the entire framework, but instead could be as simple as a financial reward for achieving a performance target. The details of indexed caps and PIMs are explained in more detail in Sections 5 and 6.

[10] The PBR rate term is defined as the period of time the PBR plan is active. For instance, the term may last from 2025 to 2029, after which a rebasing period occurs in which rates are again aligned with the utility's cost of service, and a new PBR rate term may begin.

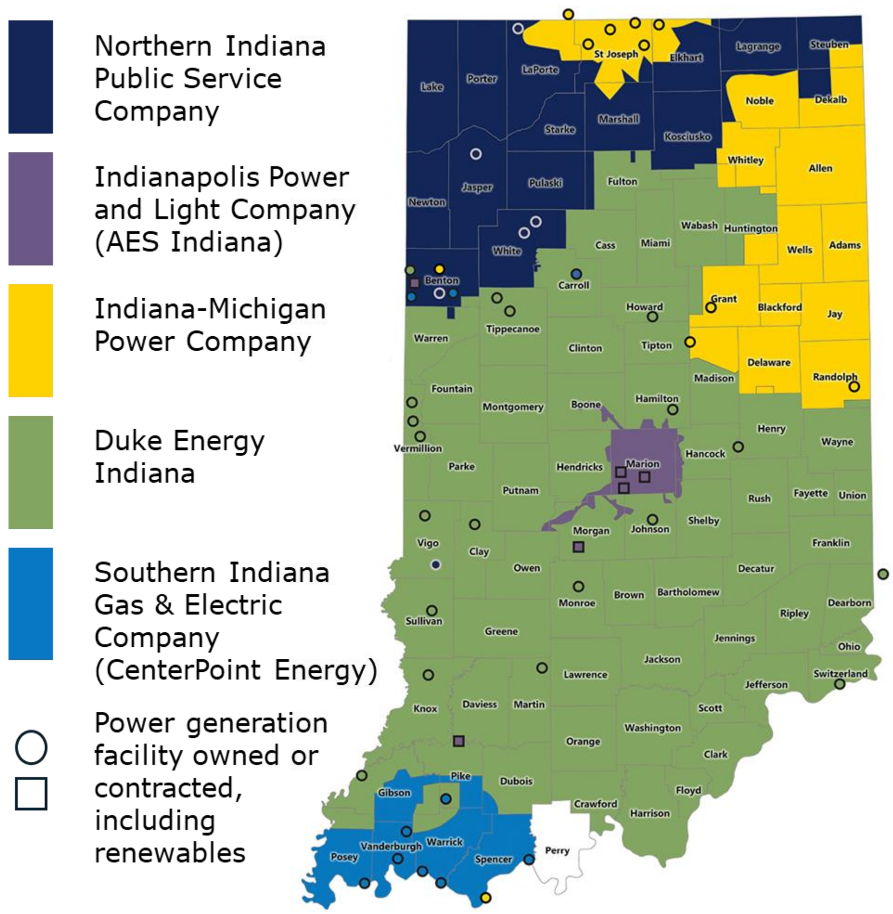
[11] In competitive markets, prices rise at the rate of inflation minus a productivity growth factor. This is often referred to as I-X in incentive regulation, where I is the rate of inflation and X is a measure of productivity growth. Revenue growth is equal to price growth plus output growth, and so a cap on revenue growth in a PBR plan may take the form I-X+G, where G is the growth rate in the utility's outputs. However, in many proceedings, utilities forego the G factor and its absence is treated as a customer dividend, or slower revenue growth which acts as a benefit to customers. These formulas are derived in Appendix B and explained throughout the report.

3 INDIANA RATEMAKING FRAMEWORK

Understanding the current regulatory context in Indiana is a critical prerequisite to making recommendations about whether PBR tools might provide benefits to the state's utilities and their customers.

Residents of Indiana receive electricity services from one of five investor-owned utilities (IOUs) or from one of the many municipally and cooperatively owned (Rural Electric Membership Cooperatives) utilities in the state. Indiana's IOUs are regulated by the Indiana Utility Regulatory Commission (IURC), which establishes the rates for consumers.[12,13] This report concerns the applicability of PBR to the state's IOUs, as PBR is not under consideration for those retail utilities outside of the IURC's jurisdiction. The service territory of Indiana's IOUs is shown in Figure 3.1.

Figure 3.1: Indiana IOUs Service Territory Map[14]



[12] Municipal utilities in Indiana are allowed by law to withdraw from parts of IURC's authority. According to the IURC 2023 Indiana Utility Guide, the majority of the municipal utilities in Indiana have withdrawn from IURC's authority.

[13] IURC regulation of cooperatively owned utilities is limited to resource planning and decision to purchase, build, or lease generation facilities. The IURC also retains authority over Wabash Valley Power Alliance's long-term financing.

[14] Indiana Energy Association, Service Territories. Accessed on September 4th, 2024.

In Section 3.1, we provide an overview of the electric utility sector in the state. Section 3.2 reviews the state's current regulatory objectives. Section 3.3 describes the ratemaking process of the state's utilities. In Section 3.4, we provide an overview of the current reporting standards in Indiana. Section 3.5 poses the question: "Can PBR Provide Improvements for Utilities and Customers in Indiana?" We explain how the IOUs in Indiana differ in significant ways from the utilities that operate under PBR in other jurisdictions and discuss key considerations for evaluating the feasibility of PBR for Indiana.

3.1 Industry Overview

As vertically integrated utilities, the IOUs in Indiana own and manage powerplants that generate electricity, build and operate transmission lines, and distribute electricity to consumers. Through these operations, the companies face rate regulation by the IURC and the Federal Energy Regulatory Commission (FERC). Each company also works with regional transmission organizations, Midcontinent Independent System Operator (MISO) and, in the case of Indiana Michigan Power Company, PJM Interconnection (PJM), for transmission planning purposes. Participation in regional transmission organizations also provides for economic dispatch of power and reliability. At the distribution level, the companies interact with retail customers to connect businesses and residential homes to the grid. The state's utilities manage a complex network of interconnected resources across functions and interact with diverse stakeholders to ensure the safe and reliable operation of the electrical grid.

Table 3.1 presents summary information about the state's electricity sector. The state's utilities operate within the MISO and PJM transmission territories, which means that each company's generators participate in wholesale market auctions.

Table 3.1: Summary of Indiana Electricity Sector

Regulatory Characteristics	
Regulated Utilities	5 IOUs
Ratemaking regulator	Indiana Utility Regulatory Commission
Transmission Operator	MISO/PJM
Alternative Regulation Elements	
Cost trackers	Yes
Revenue Decoupling	No, but LRAM exists
Revenue/Price Cap	No
Formula Rates	No
PIMs	No
Earnings Sharing Mechanisms	No

Fuel Mix[15]			
Coal	39.6%	Wind	9.2%
Natural Gas	34.0%	Solar	1.8%
Nuclear	12.0%	Other	3.4%

Energy Sector Facts[16]	
Total Installed Capacity	26,578 MW
Total Generation	90.046 GWh
Average Retail Electricity Price	11.49 cent/kWh
Electric Vehicles[17]	26,101
Battery Storage Capacity[18]	99 MW[19]

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[15] Indiana Utility Regulatory Commission, *2024 Annual Report*, p.40

[16] https://www.eia.gov/electricity/state/indiana/

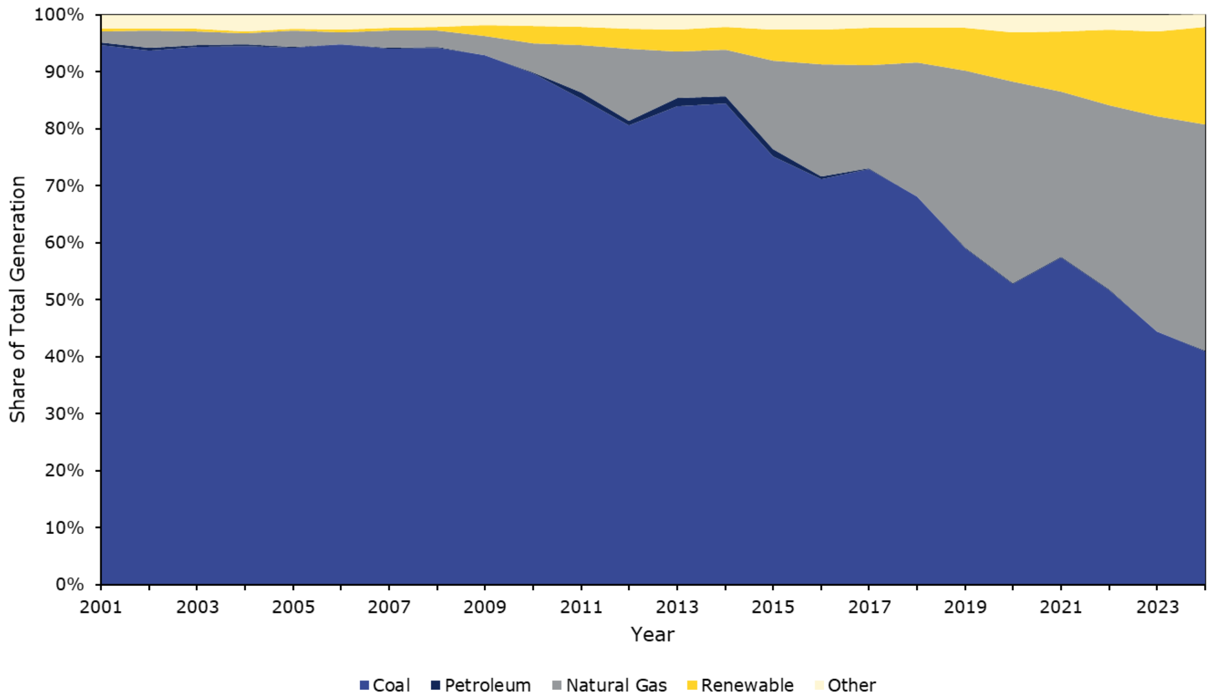
[17] Only all-electric vehicles are included. Plug-in hybrid electric vehicles are not included. (Source: https://afdc.energy.gov/data/10962)

[18] The capacity refers to total deployed capacity at the end of June 2024.

[19] Indiana Utility Regulatory Commission, *Annual Report 2024*.

Indiana's electricity production has historically been dominated by coal-based generation but is currently undergoing a significant transition toward natural gas and renewable energy sources. As shown in Figure 3.2, the state's generation mix has evolved over time, with the share of natural gas and renewables growing in the recent years. The state's major utilities are actively participating in this transformation, with several announcing gradual retirement or conversion plans for their coal facilities.

Figure 3.2: Indiana Electricity Generation Fuel Mix (2001-2024)[20]



In 2002, Indiana had the third lowest electricity rates among the fifty states. In 2023, Indiana ranked 28th.[21] The increase in rates has likely been driven by multiple concurrent factors. Construction of new generation facilities and early retirement of coal-fired generation due to environmental regulation and changing market dynamics are contributing to cost increases for the state's IOUs.[22] The increase in retail electricity prices has also been driven by a general upward trend in coal prices, as Indiana has historically largely relied on coal generation to meet the state's electricity needs. At the same time, generation costs have declined in states powered by natural gas, as horizontal drilling technology reduced fuel costs.[23] Together, these factors reduced Indiana's relative rank in retail electricity rates.

[20] Based on U.S. Energy Information Administration data on Net generation for all sectors.

[21] Table 5.6.A. Average Price of Electricity to Ultimate Customers by End-Use Sector, *Energy Information Administration.*

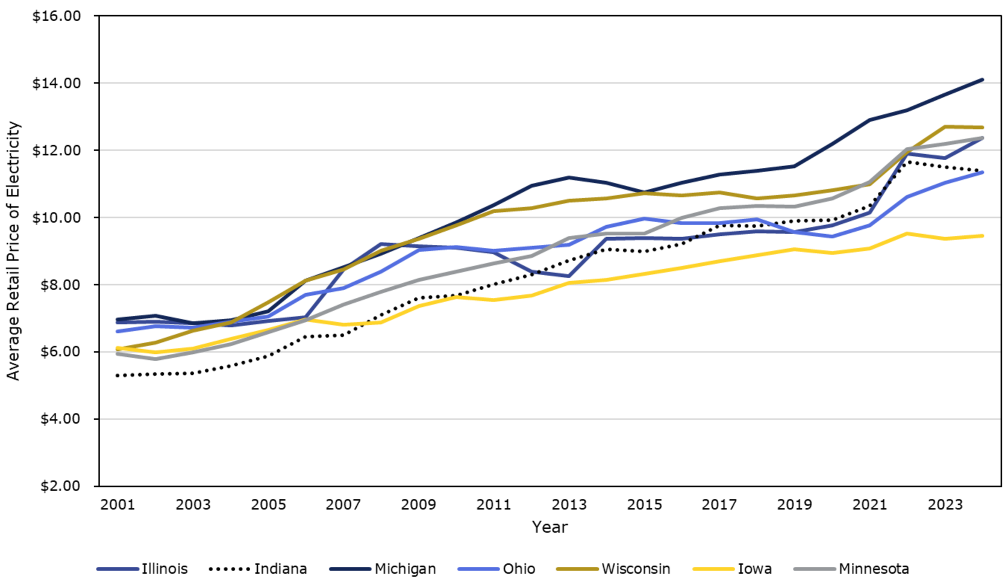
[22] Indiana Utility Regulatory Commission. *Indiana Utility Guide.* 2023.

[23] Indiana Utility Regulatory Commission. *Electricity Rate Rankings in Indiana*. January 15, 2025.

However, as shown in Figure 3.3, although retail electricity prices have grown steadily since 2001, the trend in price growth in Indiana is not dramatically different from other coal-powered midwestern states. For example, the inflation-adjusted price of electricity in Illinois from 2013 to 2023 has increased faster than in Indiana.[24] Similar to Indiana, the price increase in Illinois was partially driven by stricter emissions regulations, which led to significant shift away from coal-fired generation (from 46% of net electricity generation in 2009 to 15% in 2023).[25]

Cost growth has also placed pressure on rates beyond the Midwest. California experienced an increase in inflation adjusted price of electricity due investments in grid modernization, renewable energy resources and increased costs from wildfires and other natural disasters, while price increases in New England states were due to increases in fuel costs.[26] Notably, the majority proportion of electricity retail rate increases occur from increases in the cost of generation services, rather than distribution services.[27]

Figure 3.3:Average Retail Electricity Prices by State from 2001 to 2024[28]



Future growth in the state's electricity demand is uncertain. Retail price increases are likely to continue as the need for new generation facilities likely exceeds than in the previous two decades

[24] U.S. Energy Information Administration. *Retail electricity prices closely tracked inflation over the last 10 years.* September 11, 2024.
[25] U.S. Energy Information Administration. *Illinois State Profile Analysis*. September 19, 2024.
[26] U.S. Energy Information Administration. *Retail electricity prices closely tracked inflation over the last 10 years.* September 11, 2024.
[27] Crowley, Nicholas, and Daniel McLeod. "Trends and drivers of distribution utility costs in the United States: A descriptive analysis from 2008 to 2022." *The Electricity Journal.* Volume 37, Issue 3, April 2024.
[28] Table 5.6.A. Average Price of Electricity to Ultimate Customers by End-Use Sector, *Energy Information Administration.*

due to anticipated retirement of older coal-fired generators and replacement of capacity with natural gas-fired generating units and renewable resources.[29]

Indiana's transmission infrastructure operates within two Regional Transmission Organizations (RTOs). MISO manages most of the transmission grid in Indiana with PJM managing the transmission grid owned by Indiana Michigan Power Company. The IURC regulates the rates charged by the state's IOUs to customers. While retail rates for end use consumers include generation, distribution, and transmission components, wholesale transmission rates are regulated by FERC.

The Commission has granted permission to Indiana utilities to commit their transmission resource control to RTOs and the IOUs participate and compete in wholesale energy and capacity markets. The IOUs are required to bid their energy resources into the wholesale market, so customers benefit from the competition and lower market prices compared to the utilities' own energy production costs. If the utilities sell excess energy in the wholesale market (known as "opportunity sales"), the returns from these sales are used to offset customer costs. Utilities are incentivized to optimize these opportunity sales, and they may receive a share of the margin.[30] Differences between energy costs established in the rate case and the actual costs of providing energy are accounted for in the Fuel Adjustment Clause (FAC) adjustments. Retail customers are not able to choose their energy provider.

The utilities are also required to meet resource adequacy requirements set by the MISO and PJM.[31] The IOUs primarily meet these requirements through their own generation assets or bi-lateral agreements with other utilities and independent power producers. Similar to energy markets, the utilities can sell excess capacity in MISO's capacity markets, with the proceeds used to further offset customer costs.

This regulated participation in wholesale markets allows customers to benefit from economically dispatched energy resources, while Indiana's regulatory compact provides the IOUs with a degree of certainty to make long-term investments in generation assets to satisfy internal capacity requirements.

3.2 Indiana's Five Pillars

In 2023, Indiana's General Assembly passed House Enrolled Act No. 1007, which amended the Indiana Code. The amendment states that "it is the continuing policy of the state that the decisions concerning Indiana's electric generation resource mix, energy infrastructure, and electric service ratemaking constructs must consider reliability, affordability, resiliency, stability and environmental sustainability." These five considerations are commonly referred to as the "Five Pillars."

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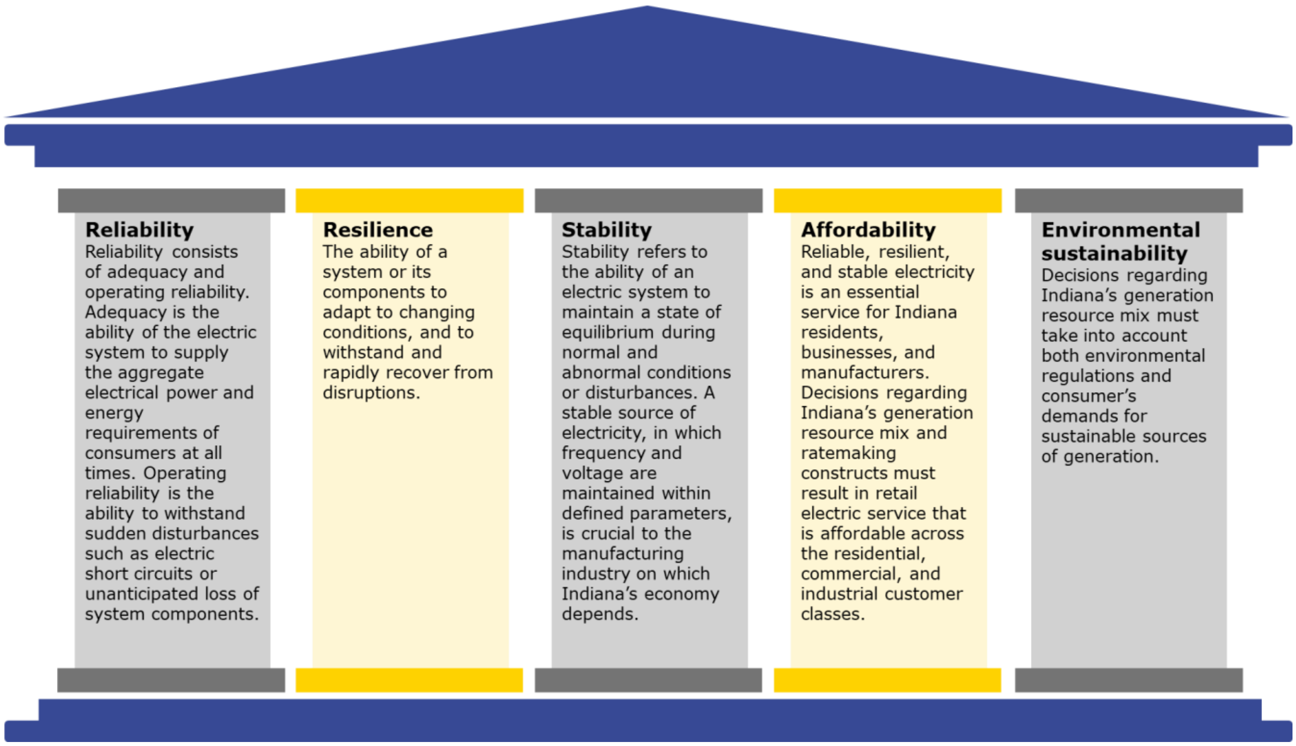
[29] Ibid.

[30] Indiana Utility Regulatory Commission, *Cause No. 43774 PJM14*, December 27,2023.

[31] Both MISO and PJM capacity markets have resource adequacy requirements that specify the level of generation capacity needed to meet forecasted demand, with a reserve margin, in order to satisfy reliability. Specifically, this is known as the Planning Reserve Margin Requirement in MISO, and the reliability (or reserve) requirement in PJM.

Figure 3.4:Indiana's Five Pillars



Utilities and stakeholders refer to the Five Pillars in rate applications and other regulatory matters, as a basis for decision making.

3.3 Ratemaking

In Indiana, electric utility ratemaking is a process overseen by the IURC. An electric utility rate case begins when a utility files a petition with the IURC to modify its rates and charges. The time between rate cases for a given utility can vary, as there is no requirement for utilities to file rate cases according to a particular schedule. However, the IOUs are limited in that requests for increases in base rates and charges cannot occur within 15 months after the filing date of its most recent request for an increase in basic rates and charges.[32,33,34] Increases in rates due to fuel cost adjustments or pre-approved cost trackers (adjustable rate mechanisms) can occur between general rate cases.

The IURC approves a cost-based revenue requirement to set retail rates for electricity for each regulated IOU (see Equation 2.1). As shown in the formula, the revenue requirement is calculated by adding a utility's operating expenses to its rate base multiplied by an allowed rate of return. Operating expenses are Commission-approved costs incurred by a utility and these costs generally include employee wages and benefits, maintenance, customer services, material

[32] Indiana Code Title 8, Article 1, Chapter 2, Section 42 (a).

[33] Even though utilities have discretion in choosing when to petition for a rate change, the IURC is required to conduct a review utilities' basic rates and charges at least once every four years. § 8-1-2-42.5(a)

[34] According to Indiana Code Title 8, Article 1, Chapter 39, Section 9 (e), implementation of TDSIC creates a rate filing requirement before the expiration of a TDSIC plan.

and supplies, energy, and administration costs, as well as taxes and depreciation. A utility's rate base is the utility's Commission-approved capitalized investment in facilities that serve customers less the accumulated depreciation. The allowed rate of return reflects utility's cost to obtain capital from lenders and shareholders. The rate calculation involves dividing the utility's revenue requirement by its billable outputs. Note that because rates are fixed between rate cases, as a utility's sales volume changes, the actual collected revenue will deviate from the revenue requirement.

In determining the revenue requirement, Indiana IOUs have the option to select one of the following test-year methods: [35]

- A forward-looking test period determined on the basis of projected data for a 12-month period beginning no later than 24 months after the date on which the utility petitions the commission for a change in its rates and charges.

- A historic test period based on 12-month period that ends not more than 270 days before the date on which the utility petitions for a change in its basic rates and charges.

- A hybrid test period based on at least 12 consecutive months of combined historic data and projected data.

3.3.1 Integrated Resource Plans in Indiana

In Indiana, each IOU files an Integrated Resource Plan (IRP). An IRP outlines what generation investments are required to meet a particular utility's customers' electricity needs over a long period of time, in this case, the next 20 years. These plans are mandated by Indiana Code § 8-1-8.5-3(e)(2) and are subject to review by the Indiana Utility Regulatory Commission (IURC).[36] The Code states that:

> *"The commission shall develop, publicize, and keep current an analysis of the long-range needs for expansion of facilities for the generation of electricity.*
> *(b) This analysis must include an estimate of:*
> *(1) the probable future growth of the use of electricity;*
> *(2) the probable needed generating reserves;*
> *(3) in the judgment of the commission, the optimal extent, size, mix, and general location of generating plants;*
> *(4) in the judgment of the commission, the optimal arrangements for statewide or regional pooling of power and arrangements with other utilities and energy suppliers to achieve maximum efficiencies for the benefit of the people of Indiana; and*
> *(5) the comparative costs of meeting future growth by other means of providing reliable, efficient, and economic electric service, including purchase of power, joint ownership of facilities, refurbishment of existing facilities, conservation (including energy efficiency), load management, distributed generation, and cogeneration."*

[35] Indiana Code Title 8, Article 1, Chapter 2, Section 42.7.
[36] Indiana Code Title 8, Article 1, Chapter 8.5, Section 3.

IRPs contain detailed information about the age, efficiency, and environmental compliance of utility generation assets. Investment in generation assets adhere to each utility's IRP, which means IOU revenue requirements, and therefore customer rates, reflect long-term planning that has been reviewed and approved by the IURC. The IRP also contains detailed information about utility demand-side management (DSM) programs, which may be employed in lieu of new generation, on the margin.

In a regulatory framework containing PBR tools to incent cost efficiencies, the utilities will still need to follow IRPs, as required by the Indiana Code. This requirement could place limitations on a utility's flexibility to delay or alter investment patterns under PBR.

3.3.2 Capital and Expense Trackers (Adjustable Rate Mechanisms)

To minimize the frequency of rate cases, Indiana IOUs are allowed to track and automatically adjust rates between rate cases to recover costs for eligible expenses. These cost trackers are generally divided into expense trackers and capital investment trackers.

An expense tracker enables the adjustment of retail rates outside of a general rate case to reflect changes in operating expenses that are largely outside the utility's control, volatile in nature, and materially significant.[37] These adjustments do not include the recovery of financing costs, but merely allow the utility to recover what it has spent on a dollar-for-dollar basis. The pass-through of unpredictable expenses to ratepayers reduces volatility in the in the utility's earnings and strengthens the utility's credit rating.

Capital investment trackers enable the IOUs to recover statutorily defined capital investments – such as clean coal technology or transmission and distribution improvements – outside of a traditional base rate case. This allows the utility recover its investment in a timely manner. Because capital investment may lead to increased operating expenditures when the plant is placed into service, capital trackers often combine the capital and expense costs into the adjustment mechanism. Credit agencies typically view such trackers favorably. According to the IURC, the benefits to ratepayers from such trackers include the mitigation of rate shock and reduction in financing costs over the life of the investment.[38]

The cost trackers used in Indiana are similar to those used in other jurisdictions, especially with regard to fuel cost adjustments, environmental compliance cost recovery, and capital expenditures. [39]

A list of Commission approved trackers is presented in Table 3.2.

[37] Indiana Utility Regulatory Commission. *Indiana Utility Guide.* 2023

[38] Ibid.

[39] For example, Duke Energy Kentucky has Environmental Surcharge Mechanism, Fuel Adjustment Clause and Demand Side Management cost trackers.

Table 3.2: Expense and Capital Investment Trackers Approved by IURC

Tracker
Fuel Adjustment Charge
Demand-side Management
Regional Transmission Operator Expenses
Opportunity Sales Sharing
Reliability Assurance or Capacity Cost
Emissions Allowance Costs
Clean Coal Technology Investment and Operating Cost
Integrated Gasification Combined Cycle
Nuclear Life-Cycle Management Cost
Federally Mandated Cyber Security Cost
Federally Mandated Environmental Cost
Settled Adjustments to Base Rates
Renewable Energy Project Investment and Operation
Transmission, Distribution, and Storage System Improvement Charge (TDSIC)[40]
Summer Reliability Adjustment

The Indiana code requires Indiana IOUs to seek approval of their energy efficiency program plans once every three years.[41] As part of their energy efficiency program filings, IOUs may request the recovery of program costs and lost revenue through the Lost Revenue Adjustment Mechanism (LRAM).[42] Lost revenue recovery allows utilities to recover deficits in revenue resulting from reduced sales due to demand side management and energy efficiency initiatives.[43,44]

Companies also have financial incentives to encourage the implementation of cost-effective energy efficiency programs. These incentives are generally tied to the value of net benefits from reductions in usage by customers.[45]

[40] TDSIC recovers costs for transmission, distribution, and storage system improvement projects that are part of an approved infrastructure improvement plan. The revenue increase from TDSIC is limited to 2% in a 12-month period. Indiana Code Title 8, Article 1, Chapter 39.

[41] Indiana Code Title 8, Article 1, Chapter 8.5.

[42] Indiana Code Title 8, Article 1, Chapter 8.5 Section 10.

[43] Lost revenue adjustments that a utility is allowed to recover account for the reduction in costs associated with reduced sales (e.g., reduced sales also likely lead to reduced fuel and variable O&M costs).

[44] The recovery of lost revenue and program costs is achieved through rate riders such as the Demand Side Management Adjustment for AES Indiana and CenterPoint Energy or the Demand-Side Management / Energy Efficiency Program Cost Rider for Indiana Michigan Power Company.

[45] Duke Energy Indiana's most recent energy efficiency plan approved in Order 45803 included incentives from 0% to 10% of the net present value of program's benefits. NIPSCO's most recent energy efficiency plan approved in Order 45849 included incentives from 0% to 9%. The level of incentives depends on the achievement of energy savings targets.

3.3.3 Phased-In Rate Adjustments

Indiana IOUs may use phased-in rate increases as a way to gradually implement rate changes over time through a rate rider. The details of a phased-in approach are determined during a rate case.

Phased-in rate adjustments make changes to rates for several years following a rate case decision, rather than increasing rates in a single year. The mechanism ensure that utility rates accurately reflect the cost of service when using forward-looking test years. The process allows for timely recovery of commission-reviewed and approved investments and costs by implementing rate increases only when specific investments or expenses are applied in serving customers. Without phased-in rate adjustments, customers might be charged for investments that have not yet created any tangible benefit or incurred actual costs in serving them.

Indiana Michigan Power Company (I&M) has requested, and the Commission has approved, phased-in rate increases in I&M's last four rate cases.[46] In an ongoing rate application by NIPSCO, the utility requested, and the settling parties have agreed on a two-phase rate implementation.[47,48] According to the settlement agreement, Step 2 rates will be implemented after the end of the forward test year (December 31, 2025) and will be based on actual net plant investments completed and placed in service no later than December 31, 2025.[49]

3.4 Service Quality Metrics and Oversight

Indiana's IOUs currently report service quality metrics. In addition, the IURC has access to regulatory mechanisms that work to ensure safe and reliable service for customers. These tools operate somewhat like PIMs, but not exactly.

Many regulators across North America require utilities to track and report various service quality metrics to ensure adequate service quality. As will be discussed in subsequent sections, such metrics can be used to safeguard against service quality degradation that may arise from cost cutting efforts pursued by the utility. In some cases, service quality metrics are tied to financial incentives for certain levels of performance.

The IURC requires the state's IOUs to report metrics related to safety, reliability, affordability, and customer satisfaction. Indiana IOUs file annual reliability reports with the IURC containing this information.[50] These annual reports include three reliability indices[51]:

- **System Average Interruption Frequency Index (SAIFI)**: SAIFI is the average number of interruptions per customer. It is calculated by dividing the total number of customer interruptions by the total number of customers.

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[46] Indiana Utility Regulatory Commission. *Cause No. 45933*. May 08, 2024.
[47] Indiana Utility Regulatory Commission. *Cause No 46120. Verified Petition for General Rate Increase*. September 12, 2024.
[48] Indiana Utility Regulatory Commission. *Cause No 46120*. *Stipulation and Settlement Agreement*. February 7, 2025.
[49] Ibid.
[50] Indiana Administrative Rules and Policies. Title 170, Article 4, Section 23(e).
[51] Indiana Utility Regulatory Commission, *Electric Utility Reliability Report 2023*.

- **System Average Interruption Duration Index (SAIDI)**: SAIDI is the average minutes of interruption per customer. It is calculated by dividing the sum of all customer interruption durations (in minutes) by the total number of customers.

- **Customer Average Interruption Duration Index (CAIDI)**: CAIDI is the average duration of interruptions or the time to restore service to interrupted customers. It is calculated by dividing SAIDI by SAIFI.

Utilities are not provided direct financial incentives for high performance in these metrics, but the IURC has in the past reduced the allowed rate of return for a utility due to unsatisfactory performance.[52]

In addition to tracking reliability metrics, each of the five IOUs file annual electric performance reports that include metrics for safety and training, vegetation management, generation, customer experience, operation metrics, affordability, and staffing. While the metrics for each utility cover similar areas of interest, the specific metrics can differ between utilities. Table 3.3 includes a non-exhaustive list of metrics tracked by IOUs.

[52] In Cause No. 43526, the Commission applied an ROE based on the lower end values of the acceptable ROE range due to NIPSCO's performance concerns.

Table 3.3: Service Quality and Operational Metrics Tracked by IOUs

Category	Metric Examples
Safety and Training	OSHA recordable incident rate
	Underground Damage Rate
	Days Away, Restricted, or Transferred (DART) Incidents
	Preventable Motor Vehicle Incidents
Vegetation Management	% of System SAIFI / SAIFI due to Vegetation Outages
	Reliability Issues Due to Forestry
Generation	Equivalent Forced Outage Factor
	Equivalent Availability Factor
	Solar Energy Yield
	Installed Net Capacity
Customer Experience/Service	Customer Complaints
	Customer Satisfaction
	Abandonment Rate
	First-Contact Resolution
	Speed of Answer
Operations	O&M Spending per Retail MWh
	CAPEX Spending per Customer
	O&M Spending per Customer
	Customers and Sales
Distributed Generation	Amount of Battery Storage
	Customer Owned Generation Capacity
Affordability	Average Rates
	Bill Delinquency
	Disconnections Due to Non-Payment
Staffing	Employee Turnover
	Demographic Metrics

3.5 Can PBR Provide Improvements for Utilities and Customers in Indiana?

The Five Pillars (discussed in Section 3.2) guide expectations of the state's IOUs regarding reliability, affordability, resiliency, stability, and environmental sustainability. The Indiana General Assembly commissioned this study to understand the impact of PBR on customers with respect to these five dimensions of service.

The tools of PBR have been used in other jurisdictions to address similar policy initiatives. As explained in Sections 4-6, when designed well, PBR can benefit both utilities and consumers. Under MYRPs, utilities may gain more predictable revenues and may obtain stronger financial incentives for cost control and innovation. Consumers may benefit from more stable rates and the potential for lower rates in the long run. PIMs can provide customers with benefits related to reliability, resiliency, and environmental sustainability. In the next several sections of this report, we offer examples of jurisdiction that have implemented these tools.

However, while PBR may provide improvements to Indiana's status quo regulatory framework, these tools are not a panacea. The realization of benefits from PBR requires carefully constructed frameworks that account for the particular circumstances of the jurisdiction and utility, as well as the values of the utility's customers. For this reason, while case studies offer valuable insights, a plan successful for one utility cannot be assumed to replicate that success if applied identically elsewhere.

Some differences exist between Indiana and other jurisdictions that have implemented PBR. First, most utilities that operate with an indexed cap are distribution-only utilities.[53] As discussed throughout this report, vertically integrated utilities, like the IOUs in Indiana, generally have larger, lumpier capital investments that may not readily align with an indexed approach to rate regulation. Second, transmission projects for Indiana's IOUs are, to a large degree, directed by the Midcontinent Independent System Operator (MISO). As such, substantial portions of the transmission investments made by Indiana's IOUs are beyond the control of utility management. The participation of Indiana's generation assets in wholesale markets also complicates the prospects of indexed caps, given the interaction of market-based remuneration for energy and an indexed cap.

It is possible that the implementation of MYRPs as described in this report could improve utility cost efficiency and reduce administrative burden in Indiana. It is also possible that PIMs could be used to address specific policy objectives. However, as recognized by stakeholders in survey responses, "the devil is in the details." We provide recommendations for best practices regarding PBR implementation throughout our discussion in Sections 4 through 6.

[53] See for example, Alberta, Ontario, British Columbia, and Massachusetts.

4 FUNDAMENTALS OF PERFORMANCE-BASED REGULATION

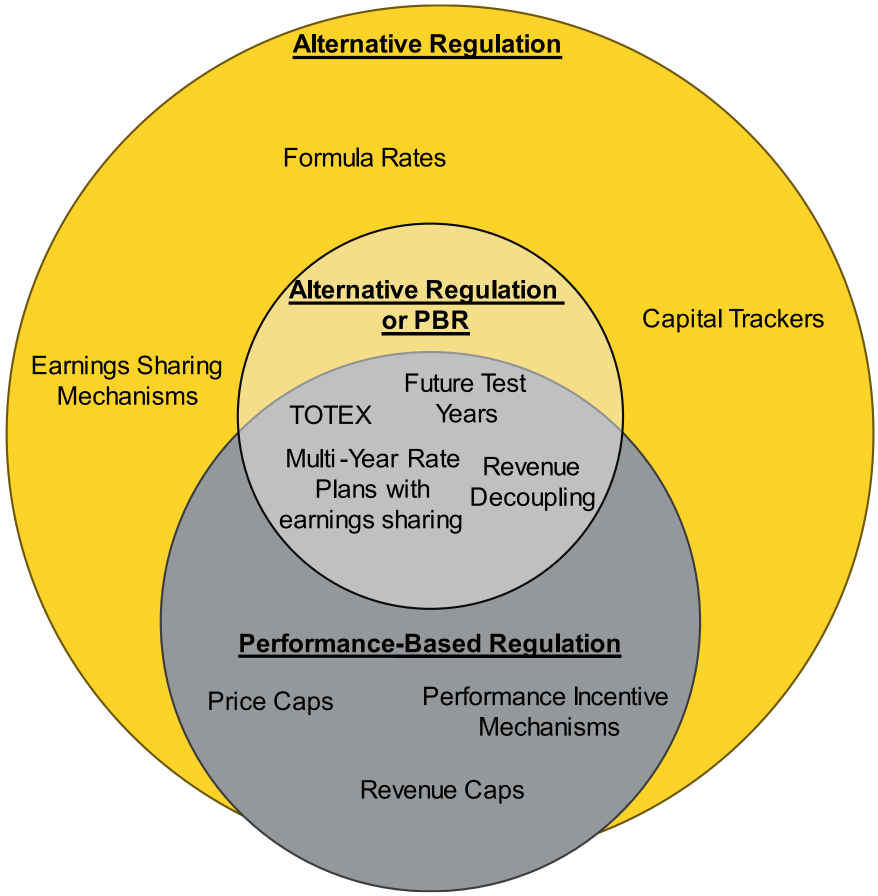
Performance-based regulation is an approach to regulating utilities that emphasizes the achievement of outcomes that benefit ratepayers and utilities through the use of financial incentives. PBR tools may create incentives for cost efficiency, enhanced service quality, or the achievement of any number of policy objectives, and may streamline the regulatory process. PBR seeks to reduce the inefficiencies of traditional regulation and align utility incentives with broader societal goals, such as improving service reliability, promoting affordability, and reducing environmental impact.

As discussed in Section 2.3, PBR can be challenging to define, as it is an umbrella term that refers to a suite of tools that lie along a spectrum of incentive power. The two primary groups of PBR tools are Multi-Year Rate Plans (MYRPs) and Performance Incentive Mechanisms (PIMs). In general, MYRPs aim to provide input efficiency: the aim is to incentivize the utility to produce its outputs using the least-cost combination of inputs (i.e., capital, labor, and materials). PIMs, on the other hand, focus on outputs. In an era of energy transition, PIMs may assist with promoting the production of outputs not traditionally required of utilities (for example, Distributed Energy Resource (DER) connections, EV charging stations, and so-called "non-wires solutions").

Defining a particular regulatory paradigm as "PBR" is complicated by the details of each regulatory framework. Some long-standing regulatory frameworks already incorporate elements of PBR, even if not explicitly identified as such. For example, the option to file forward test years in Indiana could be considered a mild form of PBR if tied to a rate stay-out period. In other cases, traditional cost-based regulatory frameworks draw upon PBR tools like PIMs to set limited portions of the utility's allowed revenue. The industry acknowledges that PBR is not a binary term and that even tools that are considered "alternative" to traditional regulation do not necessarily provide enhanced incentives to utilities.

Figure 4.1 depicts an approximate classification of various alternative regulation tools, which will be defined and discussed in subsequent sections. The figure shows that some alternative regulation mechanisms, like formula rates, Earnings Sharing Mechanisms, and capital trackers, are not generally considered PBR tools. At the same time, while PBR tools can generally be categorized as either MYRPs or PIMs, there is a gray area (e.g., a MYRP with an Earnings Sharing Mechanism (ESM)) in which regulatory frameworks have lower-powered incentive properties relative to a price or revenue cap, but more incentives for cost efficiency than traditional regulation.

Figure 4.1:Categorizing the Tools of PBR



Broadly speaking, when PBR tools are paired with traditional forms of regulation, financial risk is reduced relative to "pure PBR," but so are the utility's performance incentives. The preferred balance of risk and incentives will depend on the jurisdiction. Likewise, the feasibility of implementing PBR tools will vary by utility. As such, different jurisdictions have implemented PBR in different ways, tailoring their approach to the unique goals and priorities of the utility, the local industry structure, and the policy goals of the jurisdiction.

Subsequent sections of this report provide a discussion of PBR tools currently used in North America. In each section, we define terms, discuss benefits and drawbacks, delve into practical applications, and examine how each tool functions within a utility's regulatory framework.

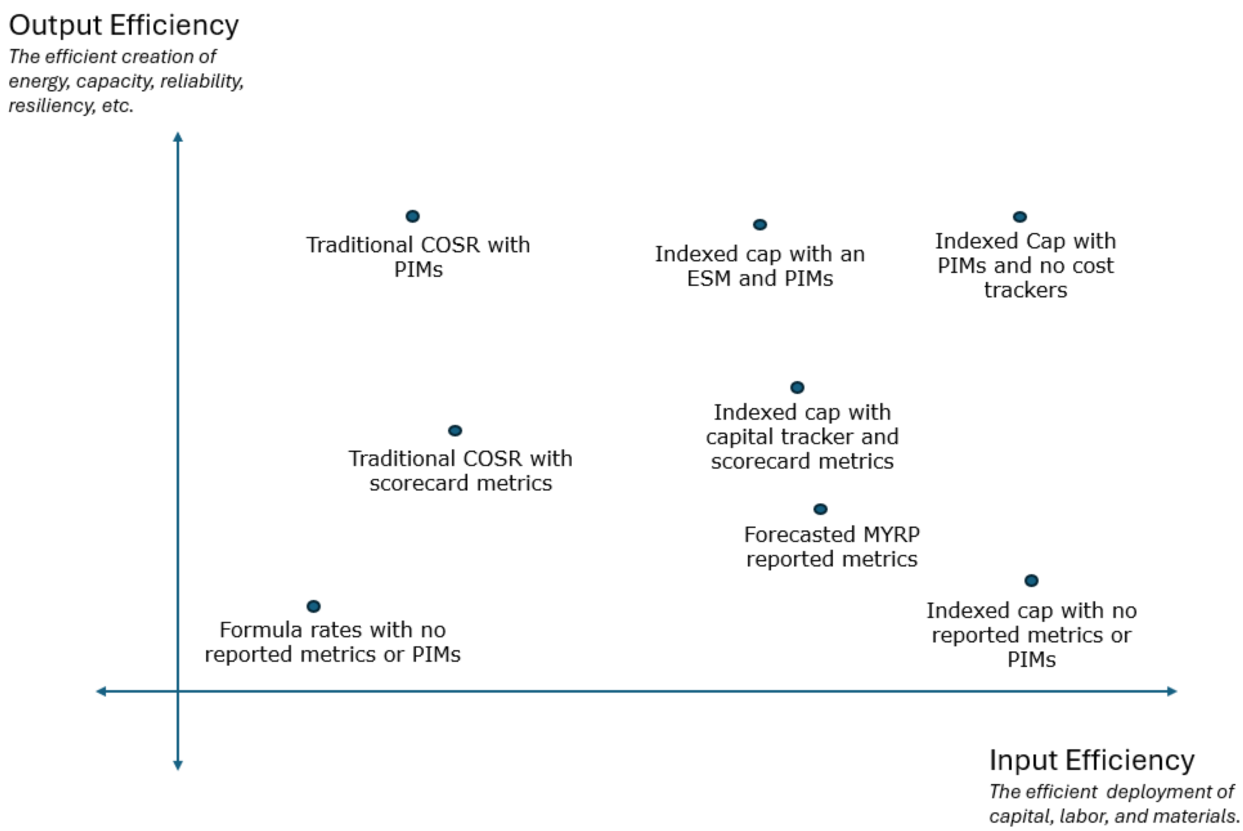
4.1 The Spectrum of Performance-Based Regulation

Figure 4.1 notwithstanding, regulatory frameworks cannot be truly placed into binary categories of "traditional" and "incentive" forms of regulation. PBR plans operate along a spectrum of incentive power, often incorporating elements of traditional COSR in an attempt to both minimize business risks and maximize benefits to customers. For example, the term "hybrid PBR" generally refers to a specific kind of framework on this spectrum, in which the utility faces an indexed cap for a portion of costs while recovering the remainder of costs on a cost-to-serve basis.

It is also worth noting that a review of indexed cap (revenue and price cap) PBR plans in North America, Australia, and Great Britain reveals that PBR frameworks differ substantially across jurisdictions. For example, different jurisdictions approach the revenue recovery of capital expenditures using different tools (see Section 5.1.5.6). Similarly, revenue recovery options for exogenous events are commonly included, the parameters that define them differ between utilities (see Section 5.1.5.4/5).

Figure 4.2 depicts the spectrum of PBR along two dimensions: input efficiency and output efficiency. The figure shows that traditional cost-of-service regulation (COSR), in which costs and revenues are closely linked by annual rate application filings to set rates based on costs, provides limited input efficiency incentives. However, adding scorecard metrics or PIMs to a traditional COSR framework can strengthen the utility's output incentives. An indexed cap with no cost trackers tends to have the strongest input efficiency incentives. The introduction of PIMs tends to strengthen a framework's output efficiency incentives. Where a given regulatory framework in the real world exists on this spectrum cannot be pinpointed, but all utility regulation frameworks exhibit some level of efficiency along these two axes.

Figure 4.2: Illustration of the Spectrum of PBR



4.2 The Limitations of PBR

This report contains substantial discussion of the beneficial outcomes that PBR can provide. In brief, such benefits include an alignment of utility incentives with policy goals and improved cost efficiency incentives. However, PBR tools also have limitations, which differ between jurisdictions and even between utilities.

The first limitation that utilities, stakeholders, and regulators encounter when adopting new regulatory tools is the administrative burden associated with transitioning. Employees across many organizations must learn how to conduct new work, build new processes for undertaking this work, and communicate to ensure new expectations are met. In some cases, PBR may add complexity to the regulatory process, requiring new calculations or the collection and conveyance of new data by utility staff. Annual filings may be required to make updates to rates. Furthermore, to the extent that PBR tools impose extensive new filing requirements, rate applications may become more burdensome, rather than less.

The subset of PBR tools classified as MYRPs aim to reduce administrative burden over the long run by reducing the frequency of rate cases. However, establishing rate cases to take place every three to five years only offers a reduction in the administrative burden if this is less frequent than the status quo. If a utility already spends a similar number of years operating between rate cases, MYRPs may not offer improvements in regulatory burden. Section 5 contains a review of additional risks and limitations of MYRPs.

Section 6.3 contains a discussion of the challenges and limitations of PIMs. For example, financial incentives based on utility performance may reward or penalize utilities for performance outcomes beyond control of utility management. There are also challenges with establishing appropriate incentive levels, among other issues.

The applicability of PBR tools depends on the unique circumstances of each utility and state regulatory environment. As discussed in Section 3.5, not all PBR tools currently in use in North America make sense for adoption in Indiana.

4.3 Literature Review of Benefits and Drawbacks of PBR

Because distribution utilities are more commonly regulated under PBR than integrated utilities, empirical PBR research largely examines distribution utilities. These studies often rely on data from other countries, as other nations have adopted PBR tools more readily than the US. Nonetheless, the IURC would benefit from a review of the evidence where available to understand the likely effects of PBR on cost efficiency, productivity, and benefits to customers.

Evidence from academic literature indicates PBR frameworks tend to improve utility cost efficiency. For example, a study of electric distribution utilities found moderate productivity growth (about 1% per year) in the UK distribution over a 29-year period from 1990 to 2019, and attributed this productivity growth, in part, to the nation's PBR framework.[54] Another study drew similar conclusions by contrasting productivity improvement from 1985 to 1998 with the smaller relative productivity growth in Japanese electric distribution sector during the same period.[55] A study focused on distribution utilities in Germany compared the outcomes of two regulatory

[54] Victor Ajayi, Karim Anaya, Michael Pollitt. *Incentive regulation, productivity growth and environmental effects: the case of electricity networks in Great Britain. The Productivity Institute Working Paper No. 012.* November 2021

[55] Toru Hattori, Tooraj Jamasb, Michael Pollitt. *Electricity Distribution in the UK and Japan: A Comparative Efficiency Analysis 1984-1998*. T*he Energy Journal*, *26*(2). 2005. p. 23-47

approaches available to German utilities: revenue caps and "yardstick" regulation,[56] finding that the incentive structure of "yardstick" regulation was associated with higher efficiency gains for utilities during the study period.[57] A study using data from Ontario and Alberta Canada found that distribution utility customers experienced slower rate escalation under price caps and revenue caps relative to a peer set of utilities operating under "traditional" regulation in the United States.[58]

Some regulators that operate under PBR have provided commentary on the results of PBR. Alberta Utilities Commission (AUC) published an evaluation of PBR, which included a survey of stakeholders to determine whether the PBR framework was achieving its original goals. The AUC concluded that PBR was effective in achieving goals of promoting efficiency incentives and that the utilities did not compromise the service quality to achieve these efficiencies.[59] In 2023, Australian Energy Regulator (AER) conducted a review of their incentive schemes applied to distribution and transmission utilities,[60] concluding that the existing Efficiency Benefits Sharing Scheme and Capital Expenditure Sharing Scheme reduced operating and capital expenditures.[61] The study also found that the Service Target Performance Incentive Scheme contributed to improvements in the number and duration of outages from 2006 to 2020.

While research indicates certain PBR tools may provide potential benefits to both utilities and customers, the evidence does not provide conclusive proof that these tools will work in Indiana. As discussed in Section 3.5, the evidence regarding price caps and revenue caps may be less applicable to the industry in Indiana, which contains major integrated utilities that operate within a multi-state ISO territory. As well, recent experience in Connecticut has demonstrated that the transition process into a new regulatory paradigm can be time consuming and costly.[62]

4.4 Current State of PBR in North America

Figure 4.3 provides an overview of PBR development across the United States. It includes information on states that are currently exploring or have previously explored PBR. Since PBR terminology can vary across different jurisdictions, this figure may not capture every state that has implemented PBR mechanisms. Nevertheless, it serves as a helpful approximation of where PBR has been applied across various U.S. jurisdictions.

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[56] The difference between the revenue cap and the "yardstick" approach is that the first takes the cost structure and adjusts it by an exogenous factor, while the yardstick moves from a cost-based cap in the first year to a benchmarked cap in the last year based on the most efficient firm.

[57] Michael Hellwig, Dominik Schober, Luís Cabral. *Low-powered vs high-powered incentives: Evidence from German electricity networks. International Journal of Industrial Organization, 73.* December 2020.

[58] Crowley, Nicholas, and Mark Meitzen. "Measuring the price impact of price-cap regulation among Canadian electricity distribution utilities." *Utilities Policy.* Volume 72, October 2021.

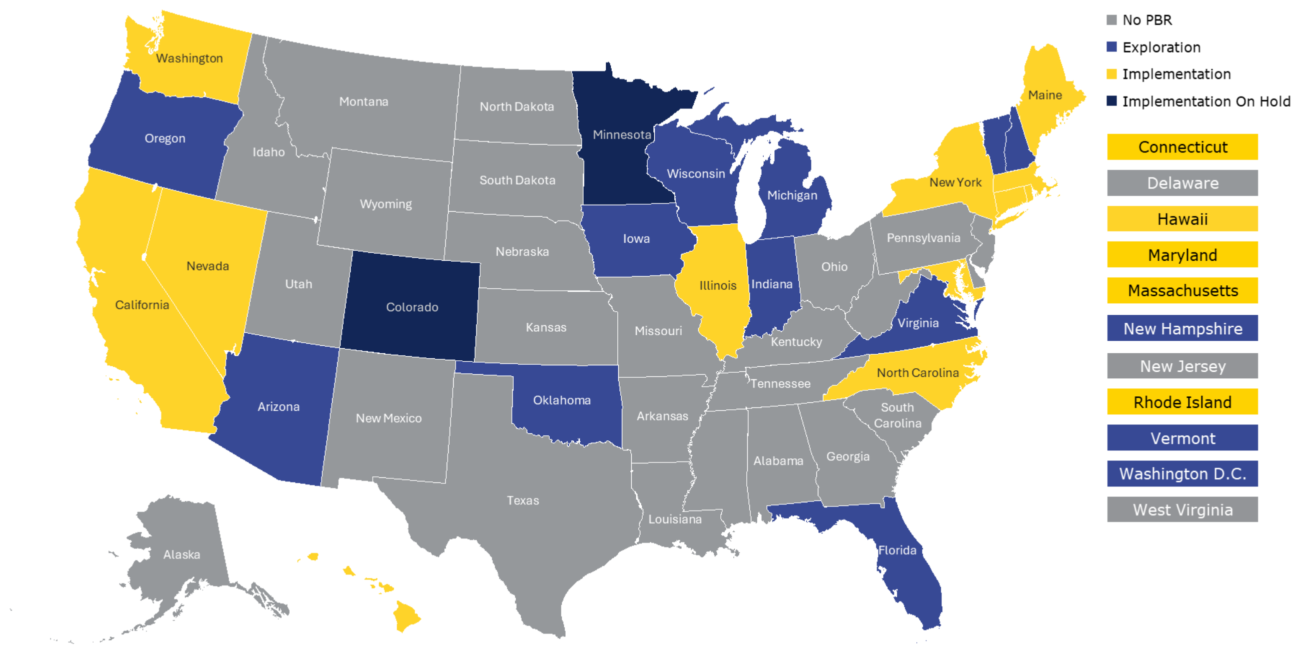
[59] Alberta Utilities Commission. *Evaluation of Performance-Based Regulation in Alberta.* June 30, 2021.

[60] Australian Energy Regulator. *Review of incentives schemes for networks. Final Decision.* April 2023

[61] Australian utilities operate under a 5-year forecasted revenue cap. The Efficiency Benefits Sharing Scheme is an Efficiency Carryover Mechanism that rewards utilities for reducing their operating expenses below forecasted costs, and the Capital Expenditure Sharing Scheme rewards utilities for reducing their capital expenditures.

[62] See for example, the Connecticut Public Utilities Regulatory Authority, Docket No. 21-05-15.

Figure 4.3: Status of PBR Across United States[63]



A review of indexed cap (revenue and price cap) PBR plans in North America, Australia, and Great Britain reveals that PBR frameworks differ substantially across jurisdictions. For example, different jurisdictions approach revenue recovery of capital expenditures with different tools. In some cases, cost forecasts inform allowed revenues during the PBR term. In others, only I-X determines revenue trajectories. Even within the same jurisdiction, PBR plans can differ between utilities. In Massachusetts, Eversource operates under a revenue cap with a K-bar capital supplement, while National Grid excludes capital from the revenue cap. In New York, utilities can file individualized PIMs that differ from other utilities in the state. While revenue recovery options for exogenous events are commonly included, the parameters that define them differ between utilities.

4.5 Guiding Principles of PBR

The design of a regulatory framework should be based on sound economic and public policy principles. Regulators in jurisdictions that have adopted PBR often articulate principles specific to incentive regulation in order to establish a basis for the design and operation of PBR plans. Utilities may rely on these principles when planning rate applications. Stakeholders may want to assess proposed frameworks using these same principles.

If the state of Indiana decides to pursue PBR for its electric utilities, we recommend soliciting stakeholder feedback regarding the following principles, which are based on decisions by the

[63] Data for this figure from "Tracking State Developments of Performance-Based Regulation," by National Association of Regulatory Utility Commissioners, April 2024. It has been modified to include other PBR developments CA Energy Consulting is currently aware of.

Alberta Utilities Commission[64] and the British Columbia Utilities Commission.[65] These principles are specific to the development of PBR frameworks, and do not supersede or negate other guiding regulatory principles (e.g., the so-called "Bonbright Principles" or Indiana's Five Pillars).

> Principle 1: The PBR plan should, to the greatest extent possible, create similar efficiency incentives compared to those experienced in a competitive market while maintaining service quality.
>
> Principle 2: The PBR plan must provide the utility with a reasonable opportunity to recover its prudently incurred costs including a fair rate of return.
>
> Principle 3: The PBR plan should recognize the unique circumstances of the company that are relevant to the PBR design.
>
> Principle 4: Customers and the regulated companies should share the benefits of a PBR plan.
>
> Principle 5: The PBR plan should be easy to understand, implement, and administer and should reduce the regulatory burden over time.

Reaching a consensus on the objectives and design of a PBR plan among industry stakeholders requires time and communication. While the principles above can be considered a useful starting point, industry conditions and preferences in Indiana may differ from those in Canada. We encourage stakeholders to provide feedback on this initial recommendation, such that a consensus may be reached. We provide in Appendix D the original list of guiding principles from Alberta and British Columbia, as well as principles from Ontario, Massachusetts, and Hawaii.

Table 4.1 contains a summary of our recommendations regarding guiding principles of PBR for the state of Indiana.

Table 4.1: Recommendations for Guiding Principles of PBR

Guiding Principles of PBR	1. The IURC should adopt a set of principles associated with incentive regulation. 2. The development of guiding principles should involve some consensus from utility stakeholders. 3. The IURC may wish to draw from the five principles set forth in this section as a starting point in the development of the state's principles.

[64] AUC Decision 2012-237, September 12, 2012, p. 7.

[65] British Columbia Utilities Commission, *Application for Approval of a Multi-Year Rate Plan for the Years 2020 through 2024*, Decision and Orders G-165-20 and G-166-20, June 22, 2020, p. 168.

5 MULTI-YEAR RATE PLANS (MYRP)

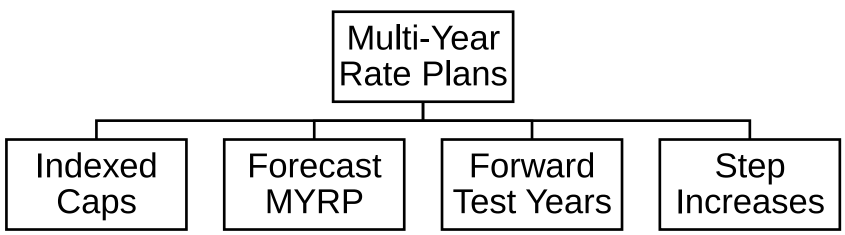
[The information on MYRPs presented in this section seeks to address Indiana Code § 8-1-2.5-6.5 (c) (1) and (2).]

In recent years, capital and operating costs faced by electric utilities in North America have increased at a faster pace than the long-term average.[66] To maintain revenues commensurate with costs in an inflationary environment, utilities will generally propose new rates through a rate application filing before the state or provincial regulator. When cost pressures accelerate, rate applications are likely to become more frequent. This can be problematic because, often, such rate applications are viewed as administratively burdensome and costly.

MYRPs are a category of alternative regulation tools that provide a framework for setting rates that can reduce the frequency of utility rate cases, facilitated by rate adjustments that either follow industry cost and productivity trends or align with the company's own costs—actual or forecasted. Thus, rather than establishing static rates that remain in effect until a future rate case—as under traditional COSR—a MYRP sets a schedule or formula that allows rates to change over the plan period. It is not until the end of the MYRP period that rates are realigned with costs through a comprehensive rate case. Most MYRP terms last three to five years.

Figure 5.1 depicts several categories of MYRPs currently employed by utilities in North America. This section will discuss the details of two of these forms of MYRP—indexed caps and forecasted MYRPs. The other two, forward test years and step increases, are similar to the forecasted MYRP approach, relying on information regarding expected costs. The figure excludes formula rates, which are not considered to be a form of PBR.

Figure 5.1: Forms of MYRP



MYRPs have existed for decades in some jurisdictions, but no two MYRPs are exactly alike. Depending on their design, MYRPs can include cost efficiency incentives for the utility, which may yield higher profits to the utility and slower rate escalation to customers.[67] If costs exceed expectations, however, returns may decline, with the impacts to net income associated with cost overruns borne by shareholders. Some, but not all, forms of MYRP may be considered PBR. The nature of a plan's incentives depends on its design. For example, while indexed cap plans like price caps and revenue caps are generally considered to be a fundamental form of PBR, formula rate plans, which adjust rates according to a utility's actual costs, would not be considered a form of PBR. We discuss the different forms of MYRPs in Sections 5.1-5.2, below.

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[66] Crowley, Nicholas, and Daniel McLeod. "Trends and drivers of distribution utility costs in the United States: A descriptive analysis from 2008 to 2022." *The Electricity Journal.* Volume 37, Issue 3, April 2024.

[67] Crowley, Nicholas, and Mark Meitzen. "Measuring the price impact of price-cap regulation among Canadian electricity distribution utilities." *Utilities Policy.* Volume 72, October 2021.

MYRPs of any kind may also layer into the framework performance incentives and efficiency targets for the utility. The goal with these additional mechanisms is to provide the utility with incentives to find efficient ways to improve service quality or promote policy objectives. We discuss such measures, known as PIMs, in Section 6.

If designed well, MYRPs can benefit both utilities and consumers. Utilities gain more predictable revenues and may obtain stronger incentives for cost control and innovation. Consumers may benefit from more stable rates, improved utility performance, and the potential for lower rates in the long run as efficiency gains are shared. However, these plans also carry risks. Customers may need to tolerate that their utility has the potential to earn profits above the allowed rate of return if costs decline over the PBR term. Likewise, utilities may face financial strain if costs rise unexpectedly. As discussed below, regulators may pair MYRPs with other mechanisms like earnings sharing or reopener clauses to mitigate these risks and maintain a balance between utility and consumer interests.

Table 5.1 highlights key advantages and challenges of MYRPs.

Table 5.1: Advantages and Challenges of MYRPs[68]

ADVANTAGES	CHALLENGES
Stable revenue: • Revenue requirements known during the MYRP period. • Rate stability for customers.	**Regulatory and intervenor resistance** • May not be comfortable with a change, particularly if it's associated with rate increases.
Cost Efficiency Incentives • Longer time between rate applications increases the incentive to find cost efficiencies.	**Data requirements:** • May require detailed revenue requirement forecasts at the account-level.
Reduced regulatory burden • Fewer rate applications.	**Rate stay-out periods:** • Restricts rate case frequency.

5.1 Indexed Caps (Price and Revenue Caps)

Indexed cap MYRPs annually adjust prices or revenues based on a formula of factors beyond the control of the company. This formula, known as the "I-X" formula, sets either prices or revenues such that the utility's costs and allowed revenues are temporarily de-linked. This allows the utility to retain profits beyond its allowed ROE over the plan term if it is able to find cost efficiencies. Only at the end of the plan term are rates reset according to the utility's cost to serve. This process is known as "rebasing." The primary objective of indexed cap regulation is to improve the cost efficiency of the utility, though indexed caps may also provide other benefits including a reduction in the frequency of rate applications over time.

[68] See, for example: "Multi-year rate plans are better than traditional ratemaking: Not so fast," Kenneth W. Costello, *The Electricity Journal,* April 2023.

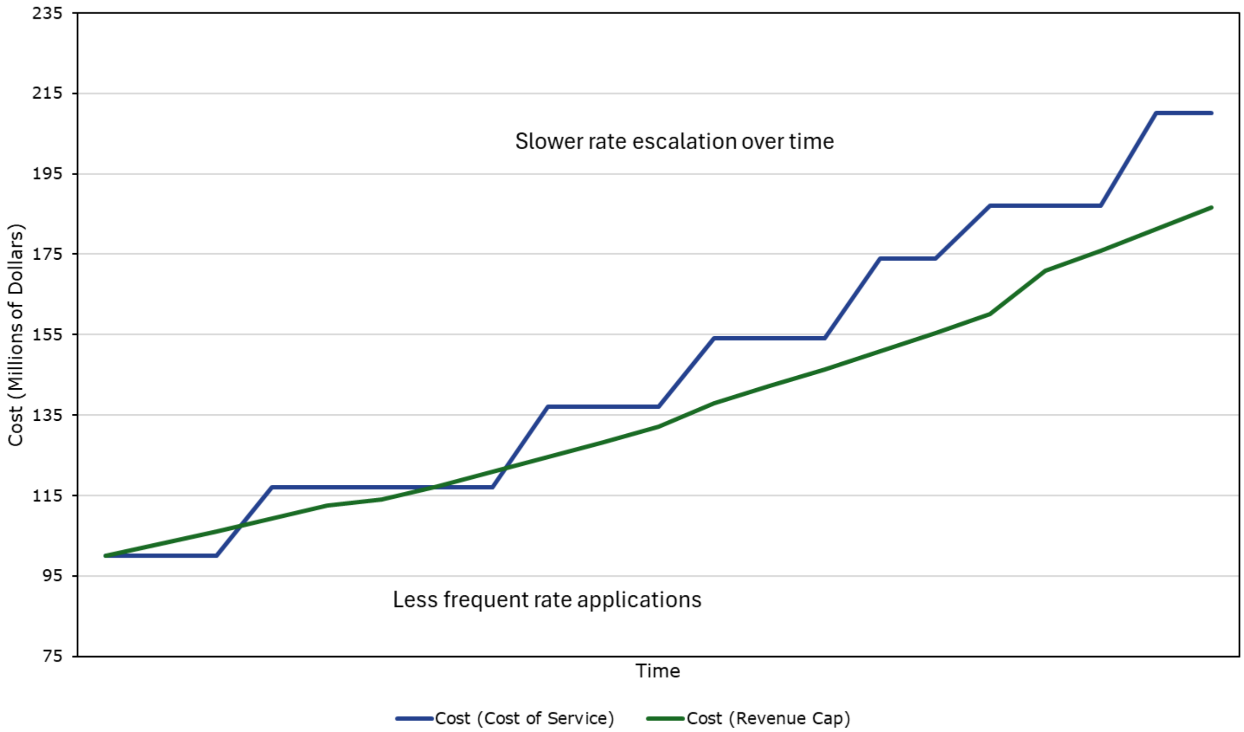
The I-X formula consists of an inflation factor (I) less industry productivity growth (X). The formula is derived from a fundamental economic principle of market competition, which states that over the long run in perfect competition, the costs and revenues of a firm are equal.[69] This principle, translated into the I-X formula, sets a price or revenue growth trajectory that mimics what would occur in competitive markets. (The derivation of the I-X formula can be found in Appendix B.) Thus, even though utilities do not experience perfect competition for distribution services, for example, a regulatory structure that places distribution revenues under an indexed cap can provide cost efficiency pressures akin to market competition within this business sector. In contrast, traditional rate-of-return regulation promotes only limited cost efficiency incentives, as cost recovery may be granted on any expenses not disqualified by the regulator.

The power of indexed cap PBR plans to provide cost efficiency incentives lies in the profit motive of the utility. In the short run, the utility may manage to earn above average returns by reducing costs. As costs are reduced, the utility's rates (or revenues) remain stable according to the I-X formula, allowing for higher earnings. At the end of the PBR term, the utility "rebases" rates according to costs. Theoretically, these costs will be lower than they would have been otherwise, as the cost efficiency incentives of the cap will have driven enhanced cost reduction. As a result, the next generation of rates will be lower than they would have been under traditional COS regulation.

Figure 5.2 provides an illustrative visualization of this concept. As shown in this graph, theory suggests that cost efficiency incentives of indexed caps reduce total utility costs over time relative to traditional cost-of-service regulation. While indexed caps do not immediately reduce rates, rates escalate more slowly over the long term.

[69] If costs were lower than revenue in the long run, other firms would enter the market and bid down prices such that eventually revenue would equal costs. If costs were higher than revenue in the long run, firms would either leave the market or go bankrupt.

Figure 5.2: How PBR Can Slow Rate Escalation over the Long Term



A resolution to accrue benefits over the long term is necessary for PBR to work properly. As recognized by the Alberta Utilities Commission, under price caps, "customers get the benefit of a more efficient utility and lower cost structures for the same or better utility service over the long term."[70] In the short run, earnings may appear lower or higher than what might be experienced under COSR, even while costs decline. If the regulator confiscates higher earnings or provides recovery for underearning through rates, the incentives of indexed caps dissolve. The regulatory economist Dr. Dennis Weisman described this phenomenon as follows:

> "[…]higher than normal earnings may simply reflect the stronger incentives for efficient performance under price cap vis a vis earnings regulation. Should this be the case, these additional earnings would not exist but for the regulator's commitment to allow the regulated firm to be the residual claimant for its realized efficiency gains. In other words, the ability on the part of the regulator to appropriate these earnings may exist only because the firm believed the regulator would not take unfair advantage of this opportunity. It follows that because PCR [price cap regulation] breaks the link between prices and costs, it must also break the link between higher than normal profits and excessive rates […]"[71]

[70] Alberta Utilities Commission. *AUC-Initiated Review Under the Reopener Provision of the 2018-2022 Performance-Based Regulation Plans for ATCO Electric and ATCO Gas.* May 22, 2024. p. 25.
[71] Dennis L. Weisman, "'Is There 'Hope' for Price Cap Regulation," Information Economics and Policy, Volume 14(3), September 2002, pages 363-364.

5.1.1 Price Caps

Price caps are a form of indexed cap that limits adjustments to customer rates over a pre-specified period of time. The price cap allows rates and costs to diverge as the utility works to find cost efficiencies to earn superior returns. At the end of the price cap term, typically around five years, the utility files a ”rebasing” rate application, resetting rates according to its cost to serve.

Although customer price growth is restricted under this approach, revenues are not restricted. The utility can increase its revenue over the plan term through sales growth. Thus, the utility can improve profits both by increased sales and by cost reduction. Conversely, however, the utility can experience revenue losses, and therefore reduced profits, if sales declines occur and/or if costs increase.

Under a price cap, energy, demand, and customer charge adjustments are made each year of the MYRP term according to an inflation rate minus industry productivity formula, generally called the "I-X" formula. By common practice, the inflation rate is updated each year using government data, while the X factor remains fixed over the plan term.[72] Table 5.2 depicts the mechanics of a price cap. Note that for the Residential customer, both the customer and energy charges are adjusted each year by the percentage obtained from I-X. For the Business customer, the customer, energy, and demand charges are all adjusted by this same percentage.

Table 5.2: Illustrative Example of a Price Cap

Term Year	I	X	I-X	Residential		Business		
				Customer	Energy (kWh)	Customer	Energy (kWh)	Demand (kW)
Year 1				$10.00	$0.080	$120.00	$0.080	$3.000
Year 2	2.00%	-1.50%	3.50%	$10.35	$0.083	$124.20	$0.083	$3.105
Year 3	2.10%	-1.50%	3.60%	$10.72	$0.086	$128.67	$0.086	$3.217
Year 4	2.00%	-1.50%	3.50%	$11.10	$0.089	$133.17	$0.089	$3.329
Year 5	2.50%	-1.50%	4.00%	$11.54	$0.092	$138.50	$0.092	$3.463

In most current price (and revenue) cap plans currently in place in North America, the X factor is set equal to zero, even though analysis of industry data indicates negative productivity growth in recent years. Under the assumption of a zero X factor, prices adjust by the rate of inflation.[73] If an empirical X factor that is negative were used to set a price cap, prices would be permitted to rise at a rate slightly above the rate of inflation. This phenomenon correlates to the fact that cost growth across the utility industry has recently exceeded the rate of inflation in the broader economy.

5.1.2 Revenue Cap

Many of the incentive qualities of price caps also apply to revenue caps. As with price caps, both the utility and its customers can obtain benefits through cost efficiencies under a revenue cap if

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[72] The X factor is generally calculated by productivity experts.

[73] Inflation is generally a weighted average of labor inflation (e.g. "average weekly earnings") and non-labor inflation (e.g., CPI), based on company splits of labor and non-labor operating expenses.

the plan is structured properly. However, some features distinguish revenue caps from price caps.

One difference involves the structure of the PBR formula. Like price caps, revenue caps rely on a formula that includes inflation and productivity growth. However, the revenue cap formula differs from the price cap formula in its inclusion of a growth factor set equal to annual growth in the number of customers. Thus, the formula under a revenue cap sets revenues according to "I-X+G," where G is equal to the annual growth in the number of the utility's customers. This formula is derived in Appendix C.

Another difference involves the utility's operation under revenue decoupling. Revenue decoupling is generally not included as part of the regulatory framework of price caps. However, most revenue cap plans in North America rely on some form of revenue decoupling to ensure that revenues do not exceed the cap over the PBR term. The I-X+G formula adjusts the utility's allowed revenue each year, and the revenue decoupling mechanism returns to customers any revenue that is collected over the cap (for example, from higher than expected sales volumes). In fact, if a revenue cap operates without a mechanism to return excess revenues to customers, it is effectively a price cap.

A third difference between price and revenue caps pertains to sales risk. For a utility with concerns about falling sales volumes, a revenue cap with revenue decoupling may be preferred because such an approach would provide revenue irrespective of changes to sales volumes. Revenue caps adjust the utility's allowed revenue according to the I-X formula, and revenue decoupling adjusts rates according to differences between the utility's expected and actual sales. Together, a revenue cap with decoupling provides the utility with revenue adjustments each year of the plan proportional to industry average cost growth, regardless of sales. In this way, a revenue cap approach with decoupling (relative to a price cap framework) can reduce risk for a utility concerned about falling demand for electricity, particularly if it recovers some of its fixed costs through an energy charge.

Such an approach does not eliminate risk, however. Under both price caps and revenue caps, the utility faces the risk that its costs could rise faster than the annual adjustment in revenues (or rates). If costs rise faster than revenue adjustments provided by I-X, the utility may need to manage with lower earnings until the end of the PBR term, at which time it can rebase its rates according to costs.

Table 5.3 depicts an illustrative example of a revenue cap. In Year 1, the prototypical utility's revenue requirement is set equal to its cost to serve ($1 billion). In each subsequent year of the five-year plan, the allowed revenue is adjusted according to an inflation rate (I), the X factor, which is based on industry productivity, and company-specific growth in the number of customers served (G). The inflation rate is updated each year of the plan, using published government data. The company also updates G using its most recent annual customer count growth rate. As with the price cap formula, the X factor remains fixed over the plan term. The allowed revenue in each year equals the previous year's allowed revenue, adjusted by I-X. A revenue decoupling mechanism can be used to true up realized revenues and allowed revenues each year.[74]

[74] Under a revenue decoupling mechanism, if realized revenues exceed the authorized revenue requirement, the utility refunds the difference to customers through a downward rate adjustment in a subsequent period. Conversely, if realized revenues fall short of the authorized revenue requirement, the

Table 5.3: Illustrative Example of a Revenue Cap[75]

Term Year	I	X	G	I-X+G	Revenue Cap (Millions USD)
Year 1					1,000
Year 2	2.00%	-1.00%	1.25%	4.25%	1,043
Year 3	2.10%	-1.00%	1.00%	4.10%	1,085
Year 4	2.00%	-1.00%	0.75%	3.75%	1,126
Year 5	2.50%	-1.00%	1.00%	4.50%	1,177

5.1.3 Setting the Base Year

Indexed caps operate by escalating a set of prices (or a company's revenue requirement) using cost information filed at the commencement of the PBR term. The revenue requirement used to set initial rates is called the "base year." Because of fluctuating costs year-to-year, the choice of base year can have a substantial influence on a utility's revenues over the PBR term. Furthermore, if the base year does not capture large, planned expenditures that will annually continue during the PBR term, the I-X formula may not provide sufficient revenue enough to meet the firm's cost of service. This problem may prove particularly troublesome for an integrated utility that plans to install large generating units during the PBR term, which might give rise to increased depreciation and operating expenses beyond the I-X formula's revenue adjustment mechanism.

The cost elements included in the first year, or base year of the program, may correspond to the cost-of-service test year revenue requirement that is recovered by the first year of new rates. It may also be the case, however, that the test year and base year are different. When this occurs, the base year, which sets the PBR term's going-in rates, contains adjustments to a test year to better align the base year with actual expenditures expected during the PBR term.

It is important to select a base year that is reflective of expenditures and costs for the utility over the duration of the PBR plan. Choosing a year with unusually low investment that does not reflect investment patterns over the term of the PBR plan can lead to an inability to fully recover the costs of future investments. Choosing a year with an unusually high level of investment that does not reflect investment patterns over the term of the PBR plan can lead to over recovery at the expense of the consumer. Therefore, it is important to choose the appropriate base year, including adjustments if necessary.

5.1.4 Annual PBR Filings

Utilities operating under PBR submit annual filings to communicate rate changes for the coming year associated with a revenue cap or price cap adjustment. The annual review generally includes updates to all relevant elements of the PBR framework:

utility recovers the shortfall from customers through an upward rate adjustment in a subsequent period. These adjustments help ensure the utility collects its authorized revenue regardless of fluctuations in sales volume.

[75] Note that the X factor for a revenue cap generally differs from the X factor for a price cap.

- *Inflation* – the formula will be updated to use the most recent government inflation numbers for the chosen inflation measure.
- *X factor* – by convention, in most frameworks, the productivity factor, or "X factor," remains static over the PBR term. However, the X factor could be updated each year with the most recent industry data.
- *Stretch Factor* – this mechanism provides immediate benefits to customers, and, like the X factor, generally remains static over the PBR term.
- *Exogenous Factors (Y and Z factors)* – the utility may be allowed to recover additional costs, as explained in subsections below.
- *Capital supplements* – the PBR plan may also include provisions for the recovery of certain capital costs.
- *Earnings sharing* – some PBR frameworks include ESMs that return a portion of earnings to customers.
- *PIMs* – rates may be adjusted for penalties or rewards based on performance under these pre-defined mechanisms.

The primary purpose of an annual filing under PBR is for the regulated utility to set rates for the forthcoming year. Other elements may also be included in the annual filing, but a streamlined annual review process with fewer components and fewer intervenor questions is more likely to yield the regulatory efficiencies commonly associated with PBR.

5.1.5 Common Elements of Indexed Cap Plans

Indexed price and revenue cap formulas are frequently supplemented with additional elements to address specific challenges faced by regulators or utilities. These include a stretch factor; a string of letter factors: Z, Y, and K factors; and other guardrails. The purpose of these additional elements is to provide benefits to customers, change the risk profile of the PBR plan, and/or to provide revenue support that is required outside of the I-X formula. Indexed caps may also be paired with an ESM (Section 5.1.5.8).

5.1.5.1 The Inflation Factor

The inflation factor is the component of an indexed cap plan that reflects the expected changes in the prices faced by the regulated utility industry. An indexed cap PBR formula should be designed to produce rates that reflect inflationary pressures on input prices, less adjustments for productivity changes, that a company is expected to experience from year to year during the term of the plan. The purpose of the inflation factor is to capture increases in the utility's input prices that are driven by macroeconomic forces.[76] In this sense, the inflation factor should account for price changes that are external to the utility's management.

There are two basic approaches to the inflation measure used in a PBR plan. The first approach is to use a measure of economy-wide *output* price inflation, such as the Gross Domestic Product Price Index (GDP-PI). This approach is more common among PBR plans in the United States. The second approach, which is more common in Canadian plans, uses some measure of industry *input* price inflation. The Fixed Weighted Index (FWI) of average hourly earnings is a good example of an input price measure of inflation pertaining to labor. A Producer Price Index for construction might be a viable inflation measure for capital additions. An input price measure of

[76] Alberta Utilities Commission, Decision 2012-237, 32.

inflation captures the prices of inputs purchased by the utility, while an output price measure reflects the prices of goods and services purchased by end consumers.[77]

Table 5.4: Recommendations for Inflation Factors

Indexed Cap Inflation Factors	If the state of Indiana adopts an indexed cap approach to PBR or a hybrid approach that places some portion of revenue under a cap, we recommend that an inflation factor be included in the PBR formula (I-X). The inflation factor should be established to reflect the electric utility sector's annual input price growth. If an output price measure of inflation is used, the X factor must be adjusted accordingly.

5.1.5.2 The X Factor

The productivity offset, or X factor, is a key element of indexed cap plans. Coupled with the inflation factor in the I-X formula, the X factor is a mechanism designed such that changes in utility rates or revenues reflect the change in industry input prices and the rate of industry productivity growth. Accordingly, combined with the I factor, I–X represents the expected unit cost performance of an average performing company in the industry when productivity is defined with customers as the output measure.[78] Together, the inflation and X factors mimic the pressures of a competitive market by pegging company rates or revenues to its performance in comparison to peer companies. To the extent that the firm is more productive than its peers and is able to produce at lower costs, it earns a superior return. Conversely, firms that are less productive than the industry average earn lower returns.[79] According to economic principles explained in Appendix C, the use of expected productivity in setting the X factor provides the appropriate level of attrition relief to the regulated firm under an indexed cap.

In some cases, regulators have set the revenue or price cap equal to input price inflation with a zero or arbitrary X factor. However, this is not the correct approach and could cause problems for the utility operating under the cap. The I factor only captures the change in input prices faced by the industry. It does not capture the required change in input *quantities.* A simple example illustrates the problem with this approach. Suppose a utility must replace a large portion of its poles and suppose the price of a single pole does not change from year to year. In this case, the I factor would equal zero, because the input price remains unchanged. If revenue were allowed to increase only by the I factor, the utility's revenue growth from one year to the next would equal 0%. This would be an insufficient revenue increase, because the change in the quantity of poles will increase costs, such that total costs exceed total revenues. Although this is a simplified example, this concept, in essence, is what the X factor represents: industry productivity, or a

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[77] Using an input price approach simplifies the X factor calculation. If an output price measure were used, the X factor would be modified to include a TFP growth differential between the economy and the utility, as well as an input price differential between the economy and the utility. No such differential is required to set the X factor when using an input price measure of inflation. Instead, the X factor under an input price inflation measure simply equals industry TFP growth.

[78] Where the unit cost equals total cost per customer.

[79] William J. Baumol, "Productivity-incentive clauses and rate adjustment for inflation," *Public Utilities Fortnightly,* 1982.

change in input quantities relative to the change in outputs. By setting the revenue cap with both an empirical inflation measure and an empirical productivity measure, the revenue cap will be set such that utility revenues are allowed to grow with the industry cost growth experience.

Because the I-X formula aims to provide pressure that imitates the competitive market that is external to the regulated firm, the X factor is generally set using industry data, not data specific to the company under the revenue cap. A total factor productivity (TFP) growth study using a sample of peer companies is typically used to set the appropriate value for the X factor.[80] Another method, known as the Kahn Methodology, provides similar information using financial data—as opposed to "real outputs" measured in TFP growth studies—and is employed in the price regulation of U.S. oil pipelines.

Table 5.5: Recommendations for X Factors

Indexed Cap X Factors	If the state of Indiana adopts an indexed cap approach to PBR or a hybrid approach that places some portion of revenue under a cap, we recommend that an X factor be included in the PBR formula (I-X). This X factor should be calculated from an industry TFP growth or Kahn Methodology analysis.

5.1.5.3 Stretch Factors

The primary objective of indexed cap PBR frameworks is to provide the regulated utility with an incentive to seek improvements in cost efficiency during the PBR term. Under an I-X cap and in the absence of any other plan elements, cost efficiency gains are entirely retained as profits to the utility's shareholders until the end of the PBR term, at which time customers would benefit in the form of lower rates (as the revenue requirement is reset based on a cost-of-service rate case). Regulators may prefer that some of these gains in cost efficiency are returned to customers immediately, rather than retained by the utility until the end of the PBR term.[81] A "stretch factor," S, reduces the growth in prices (or revenues) under the PBR term, by incorporating an additional factor in the I-X formula.

For example, the price formula with a stretch factor is:

$$\%\Delta price = I - X - S \tag{5.1}$$

Where S is generally a positive percentage in the range of 0.00% to 0.60%. The regulator subtracts the stretch factor from the I-X cap to reduce the rate of growth in price and share the

[80] If the X factor were to be based on changes in the regulated firm's productivity, price cap regulation would function in similar fashion to cost of service regulation. Jeffrey I. Bernstein and David E.M. Sappington, "Setting the X Factor in Price-Cap Regulation Plans," *Journal of Regulatory Economics*, Vol. 16, 1999, p. 9.

[81] Another reason cited for introducing a stretch factor is a desire to return a share of reduced regulatory burden to customers. The stretch factor might also serve as a signal to firms and stakeholders of what the regulator expects the firm to do. Some efficiency changes a utility might seek to make could incur more stakeholder opposition from employees or customers if the benefits of those changes do not pass through to customers in a timely fashion. It is also worth noting that omitting a stretch factor might allow the firm to remain "statically inefficient" over the PBR term, continuing to operate at a higher cost level than its peers.

expected cost reductions with customers. Thus, customers will face price growth slower than what theory suggests would be expected in a competitive market.

A stretch factor will not change the incentives for efficiency—no matter what price the regulator sets, the firm maximizes profits by containing cost and improving efficiency. Instead, setting a stretch factor is a question of distributional fairness of over what time frame consumers are entitled to a portion of firm-specific efficiency gains through lower utility rates.

The academic literature has alluded to a connection between cost benchmarking results and stretch factors.[82] However, in practice, regulators have calibrated stretch factors without support from an empirical cost benchmarking study. More commonly, benchmarking studies have informed the choice of stretch factor, but relies heavily on "regulatory judgement." We recommend that stretch factors use cost benchmarking information, rather than blind judgement, as the data is publicly available via the FERC Form 1.

Table 5.6: Recommendations for Stretch Factors

Indexed Cap Stretch Factors	If the state of Indiana adopts an indexed cap approach to PBR or a hybrid approach that places some portion of revenue under a cap, we recommend that a stretch factor be included in the formula (I-X-S). This stretch factor should be company-specific based on industry cost benchmarking analysis.

5.1.5.4 Z Factors

Under indexed cap plans, the utility generally agrees not to file rate applications during the term of the plan. This means that companies operating under price caps or revenue caps must manage with a constrained spending envelope over a period that could be five years or longer. Most PBR frameworks include provisions to account for costs that may rise during this time for reasons beyond the control of the utility's management.

One type of costs often recovered outside of a price or revenue cap are exogenous events—one-time costs that arise for reasons clearly beyond the utility's control. The mechanism to recover such costs is called a "Z factor."[83] The Z factor allows for an adjustment to a company's revenues to account for a significant financial impact (either positive or negative) of a one-time event outside of the control of the company and for which the company has no other reasonable opportunity to recover the costs within the PBR formula. Generally, a relevant Z factor event is one that is unknown (and unknowable) to the company at the start of the PBR regime; that has a substantial impact on the company's earnings; and for which both the event and the financial impact of the event on the company's earnings are largely beyond the company's control.[84] Most indexed cap PBR plans set a minimum threshold (i.e., "materiality") for Z factor events, under which costs are not eligible for Z factor recovery.

[82] Lowry, M.N., Getachew, L., Hovde, D., 2005. Econometric Benchmarking of Cost Performance: The Case of US Power Distributors. The Energy Journal 26 (3), 75–92
[83] See, for example: BC Utilities Commission, Decision and Order G-388-21, 51. Also see, Alberta Utilities Commission, Decision 2012-237, 108.
[84] Dennis Weisman. "Assessing the Treatment of Capital Expenditures in PBR Plans." *Fiscal 2020 to Fiscal 2021 Revenue Requirement Application.* Ch. 11. Appendix GG. p. 36.

In Massachusetts, for example, utilities under PBR can recover, through a Z factor, incremental costs resulting from changes in tax laws that uniquely affect the relevant industry; accounting changes unique to the relevant industry; and regulatory, judicial, or legislative changes uniquely affecting the industry.[85] Other examples that might be eligible for recovery through a Z factor are as follows:

- Government policy changes;
- Judicial, legislative, or administrative changes, orders, or directions;
- Major environmental events (e.g., a major seismic event, flood, fire, pandemic);
- Major labor disruption or supply chain event;
- Acts of war, terrorism, or violence;
- Changes in accounting treatment, standards, or policies; and
- Changes in revenue requirements due to regulatory decisions.

Exogenous factors like the Z factor provide guardrails for the PBR framework, to mitigate the risk that major unforeseen events will impact the utility's finances so materially as to potentially inflict damage on customer service quality or the utility's ability to raise capital.

Table 5.7: Recommendations for Z Factors

Z Factors	If the state of Indiana adopts an indexed cap or forecasted MYRP approach to PBR or a hybrid approach that places some portion of revenue under a cap, we recommend that a Z factor be included in the PBR framework. The Z factor should be company-specific and have a materiality threshold roughly in line with thresholds seen in other jurisdictions.

5.1.5.5 Y Factors

During the PBR term, portions of a utility's costs may be volatile for reasons other than one-time exogenous events. Ongoing costs, like fuel to power generation, may fluctuate dramatically, such that they diverge from the indexed cap formula but do not meet the criteria for a Z factor.

Y factor costs are those recurring exogenous costs that do not qualify for Z factor treatment and that should be directly recovered from customers or refunded to them. The purpose of Y factors is to allow for separate cost recovery of those costs outside of management's control, and are therefore recovered outside of the price or revenue cap. Y factor costs could either be costs the company is required to pay to a third party (such as the electricity purchases on the open market) or other regulator-approved costs incurred by the company for flow through to customers.[86]

Some jurisdictions use a term other than "Y factor" when referring to flow-through costs, though these plans still include provisions for such costs.[87] In these cases, a different name fulfills the same purpose as Y factors. For example, FortisBC recognizes "flow-through" costs often through

[85] Massachusetts Department of Public Utilities, Docket D.P.U. 17-05, 396

[86] See, for example: Alberta Utilities Commission, Decision 2012-237, 131.

[87] The term does not appear to be used in Ontario, Massachusetts, Hawaii, or by FortisBC.

variance accounts. These items include depreciation expense, insurance premiums, income and property taxes, interest expense, the cost of energy, and certain forecasted O&M expenses. Variances related to these items are captured in each of the utility's general flow-through deferral accounts. Other revenue requirement variances are also flowed through to rates using specific deferral accounts.[88] The Hawaiian utilities operating under PBR recover costs pertaining to energy costs and purchased power, pension costs, demand-side management costs, renewable energy infrastructure program costs, under "cost trackers," which is a term that is generally synonymous with the term Y factor.

Examples of Y factors explicitly listed by the Alberta Utilities Commission as eligible include system operator fees, farm transmission costs, costs arising from Commission directives, tax changes, municipal fees, load balancing deferral accounts, and production abandonment costs. In Quebec, the Y factor included retirement costs, which have significant volatility, but the Régie determined that the Y factor would not include tax changes, which, if large enough, could be recovered through the Z factor.[89]

Our research indicates that the classification of costs as eligible for Y factor, or flow-through, treatment varies by jurisdiction. To some extent, these differences may arise because of differences in industry structure between different regions. Like the Z factor, Y factors provide stability to the utility during the rate case stay-out period, so that it recovers potentially volatile costs outside of its control without requiring a new rate case. In the state of Indiana, costs eligible for Y factor may include fuel adjustment charges, green power charges, and environmental compliance costs, and other costs found in Table 3.2.

Table 5.8: Recommendations for Y Factors

Y Factors	If the state of Indiana adopts an indexed cap or forecasted MYRP approach to PBR or a hybrid approach that places some portion of revenue under a cap, we recommend that a Y factor be included in the PBR framework. The Y factor should be company-specific and the costs eligible for Y factor treatment should be clearly defined at the outset of the PBR term.

5.1.5.6 K (Capital) Factors

Electric utilities require capital outlays to maintain and grow service in accordance with their obligation to serve customers and, recently, electric utilities across the US have increased capital spending on new technologies to support electrification of the economy. Utility revenue constraints under PBR therefore create concerns with respect to maintaining service. Revenue deficiencies may arise if the indexed cap base year revenue requirement does not reflect capital needs in subsequent years during the PBR term, or if capital expenditures exhibit high variability. As such, PBR frameworks generally contain revenue support for capital expenditures.

[88] BC Utilities Commission, Orders G-165-20 and G-166-20, 65.
[89] Régie de l'énergie, *Décision sur l'établissement des modalités du mécanisme de réglementation incitative*, D-2019-060, May 16, 2019, p. 53.

Different jurisdictions in which utilities operate under indexed cap PBR plans have different ways of determining what capital should be recovered under a formula and different ways of managing revenue recovery of capital outside of the I-X formula. Because every utility is different and many PBR regimes are still in their early stages, the industry has not settled on best practice approach to recovering capital under PBR frameworks.

Approaches have also differed across time within jurisdictions. For example, the first generation PBR plan for Alberta distribution utilities allowed for capital tracker filings, which generated excessive regulatory processing, leading ultimately to a change in the second generation PBR plan. Similarly, the British Columbia Utilities Commission (BCUC) found that FortisBC, Inc. could not sufficiently recover revenue for capital spending under its 2014-2018 plan, such that capital was removed from formula treatment under the 2018-2022 plan and is now recovered on a forecasted cost-of-service basis.

A lack of homogeneity across jurisdictions and across time suggests two things. First, although supplemental revenue for capital is common across PBR plans, regulators have flexibility in setting the design of capital recovery mechanisms. Second, the success of each capital supplement methodology is not well tested, as most methods have only existed for a short span of time. Where empirical information on the benefits or limitations of each approach is lacking, economic theory can provide guidance.

There are many differing methods of capital cost recovery under PBR. Table 5.9 provides a summary.

Table 5.9: Summary of Capital Recovery Approaches Under PBR

Approach	Jurisdictions	Methodology
Forecasted Capital	British Columbia; Australia	In the PBR proceeding to set initial rates, the utility establishes a forecast of capital spending costs over the PBR term and recovers these costs through rates.
Cost-of-service (capital trackers)	Massachusetts	Gas utilities in Massachusetts may recover capital expenditures beyond the PBR formula under the state's Gas Safety Enhancement Program.
Project-Specific	Ontario; Hawaii	Utilities may recover costs for projects that meet certain criteria. Known as the Exceptional Project Recovery Mechanism in Hawaii,[90] and the Incremental Capital Module in Ontario.[91,92]
K-Bar	Massachusetts, Alberta	This approach provides a capital spending envelope based on the utility's own trend in historical capital spending.[93]

The advantage of the Forecasted Capital approach is that utilities receive their expected revenue shortfall for capital expenses, while still maintaining some incentive to contain those expenses. For instance, in British Columbia, the difference between actual and forecasted expenses are subject to an ESM, meaning that if the utility spends less than the forecast, it is able to retain some of these savings as profit. Additionally, this approach reduces regulatory burden by setting the forecast before the term begins and leaving any variances between actual and forecasted spending to be handled mechanistically through the ESM rather than through annual cost-of-service proceedings. The primary disadvantage of the Forecasted Capital approach is that it may incentivize the utility to over-forecast capital expenses if it is able to retain any savings as profit. However, tradeoff can be mitigated through prudency reviews before and after the PBR term, or by forecast penalty terms.

A cost-of-service approach to capital expense recovery has the advantage of minimizing financial risk to the utility, which may be essential during a period of transition in which significant capital investment is necessary. Well-designed capital trackers can reduce the regulatory lag for utilities,

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[90] Hawaii Public Utilities Commission, *In the Matter of the Application of Hawaiian Electric Company, Inc. For Approval to Commit Funds in Excess of $2,500,000 (excluding customer contributions) for the PZ.005125 – Kahe-Waiau 138 kV Undergrounding Project and to Recover Costs through the Exceptional Project Recovery Mechanism,* Decision and Order No. 38451 Docket No. 2021-0086, p. 62.

[91] Ontario Energy Board, *An Application by Hydro One Networks Inc. for [an order approving distribution rates],* EB-2008-0187, May 13, 2009.

[92] Note, Ontario distribution utilities may also recover capital costs under another mechanism, known as the Advanced Capital Module.

[93] For more information, see here: Alberta Utilities Commission, Rebasing for the 2018-2022 PBR Plans for Alberta Electric and Gas Distribution Utilities, Decision 22394-D01-2018, February 5, 2018.

increase the willingness of utilities to invest in critical infrastructure. In addition, capital trackers ensure that ratepayers will only fund projects that have been prudently incurred and placed into service. However, capital trackers could also lead to capital over-investment and reduce utilities' incentive to control costs. Furthermore, annual cost-of-service reviews for capital spending are costly and run counter to the goals of PBR.

The advantage of the Project-Specific approach is that it recognizes that a cost-of-service is necessary for out-of-the-ordinary projects whose costs cannot be accurately forecasted, but retains the high-powered incentive structure for the majority of capital spending. The disadvantage of this approach is that it may be insufficient to address capital funding shortfalls more generally, particularly if there is a project-specific materiality threshold that must be reached in order for the utility to apply for project funding, and the utility faces shortfalls on many projects that are beneath this threshold.

K-bar, like the Forecasted Capital approach, has the advantage of retaining the desired cost containment incentives of an effective PBR plan, as the K-bar funding for a given year is determined mechanistically based on investment decisions in the past, as opposed to being tied directly to what is spent in that year. However, K-bar has the disadvantage of being more difficult to understand, and hinges on the assumption that investment decisions in the past are an accurate predictor for investment decisions in the present, which may not hold.

A review of capital treatment across North American PBR plans revealed that the industry has not reached a consensus on capital recovery under PBR. Each approach to capital recovery gives rise to a certain level of complexity, risk, regulatory burden, and incentive pressure. However, the overarching similarity across PBR frameworks is that utilities have been granted means for recovering additional revenues, beyond what might be permitted under the I-X formula, in order to meet capital spending needs.

Table 5.10: Recommendations for Capital Factors

Capital Factors	If the state of Indiana adopts an indexed cap regulatory framework, we recommend consideration of some form of capital supplement on an as-needed basis. The capital factor should be company-specific and the costs eligible for capital factor treatment should be clearly defined at the outset of the PBR term. Economic principles and the guidelines of PBR should be considered in the design of the capital factor.

5.1.5.7 Reopeners

A fundamental feature of MYRPs is a longer period of time between traditional revenue requirement applications for the utility under the plan. This time between "rebasing" results in a prolonged separation of costs and revenues, providing the utility with enhanced efficiency incentives but also enhanced risk. The I-X formula provides some attrition relief for utilities over the PBR term, but because costs and revenues are separated over the PBR term by design, sufficient cost recovery only persists if the utility experiences stable cost escalation in line with the formula. Since the automatic nature of the I-X formula does not adjust annual revenues for sustained changes in utility costs in the comprehensive manner that rate applications adjust revenues, a utility operating under PBR could potentially experience earnings that are dramatically higher or lower than the amount provided under the I-X formula. To protect against an untenable divergence of costs and collected revenues, PBR plans include "reopeners," or mechanisms that allow for review of the regulated entity's PBR plan during the PBR term and potential relief in the form of adjustments to the PBR plan or exiting the plan completely in the event certain predefined conditions occur.

Reopeners are a common feature of PBR frameworks in North America. It is generally understood that depending on the findings of the regulator, triggering a reopener could result in modifications to a utility's existing PBR plan, termination of the plan, or continuation of the plan. If a problem with the PBR framework is identified, possible remedies to a reopener might include the following:

- Fix design issues – For example, the inflation factor that adjusts rates in Alberta consists of a weighted average of a Fixed Weighted Index (FWI) for labor, and the province's Consumer Price Index (CPI). If the FWI were to deviate dramatically from the price of labor experienced by Alberta distributors, the inflation factor may need to be fixed before the end of the PBR term. Another example would be if a capital supplement were initially critical to providing funding support for necessary investments, but is no longer appropriate for some reason, the reopener could modify this revenue adjustment parameter on a going-forward basis.
- Provide solutions to operational problems – If the utility responds to cost efficiency incentives by reducing costs in a manner that causes concerns for the regulator, targeted solutions like PIMs could be added to provide incentives for the utility to spend efficiently to ensure that service quality does not decline.
- Rebase for unexpected costs – Costs may rise on a broad scale. Likewise, broad-based cost declines may occur. In such cases, rate rebasing may be appropriate and be conducted on a going-forward basis.
- Fix billing errors – If the utility collected revenue that was not correct—for example, because of billing errors, this revenue would be refunded to customers.
- Facilitate an off-ramp – If the PBR framework is found to be fundamentally flawed such that it cannot be modified and continued, an off-ramp allows the utility to leave PBR and transition back to traditional cost-of-service regulation.

Table 5.11: Recommendations for Reopeners

Reopeners	If the state of Indiana adopts an indexed cap regulatory framework or a forecasted MYRP, we recommend that some form of reopener be included. The reopener provision should be clearly defined, with a clear description of how it would be applied in the event of being triggered.

5.1.5.8 Earnings Sharing Mechanisms (ESMs)

ESMs manage the risk of a utility over- or under-earning relative to its allowed ROE. Utilities operating with ESMs share earnings that exceed (or fall short of) a predetermined threshold, either reducing rates for customers in the case of overearning or, depending on the design, providing financial relief to utilities in the event of underearning. As shown in Figure 4.1, above, ESMs are a form of alternative regulation distinct from PBR. This is because ESMs relink the utility's revenues and costs, removing or mitigating cost efficiency incentives. However, ESM are often included in PBR plans as a means of managing risk.

Under both traditional and performance-based regulation, regulators establish a target ROE for the utility through the rate application process. In subsequent years, rates are set according to a revenue requirement that includes this authorized return. Under a symmetrical ESM, if actual earnings exceed or fall short of the target ROE, some proportion of the excess or shortfall is shared between the utility and its customers according to a predetermined formula. This sharing can be structured in tiers, with different sharing percentages applied depending on the magnitude of the deviation of realized earnings from the target or allowed ROE.

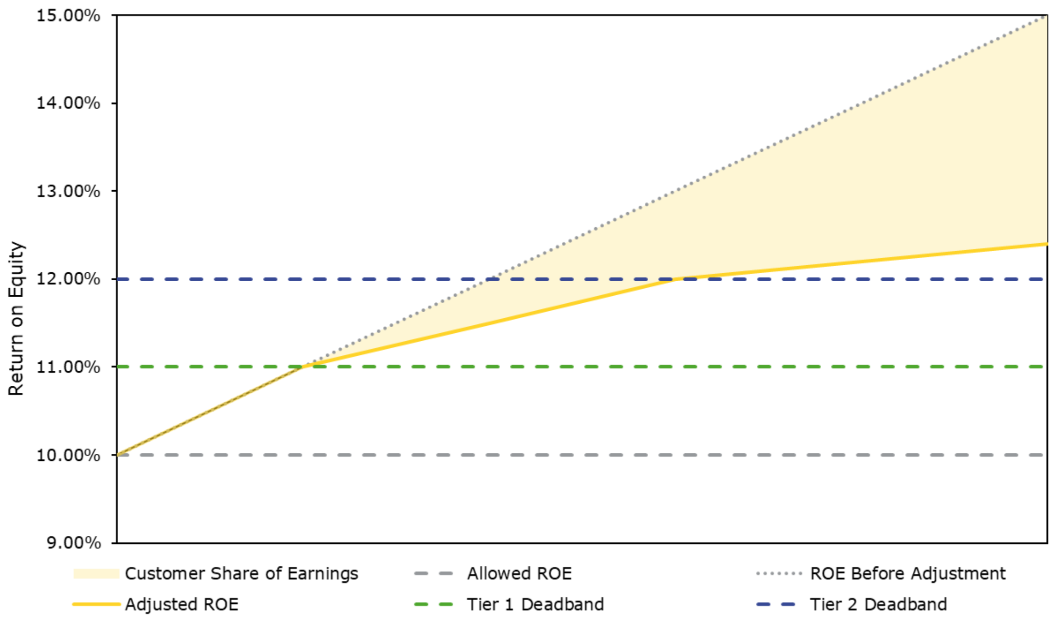
A key feature of many ESMs is the use of so-called "deadbands." A deadband is the range around the target ROE within which no sharing occurs. Earnings within the deadband are retained entirely by the utility, insulating it from small fluctuations while maintaining the sharing mechanism for larger deviations. When earnings fall outside the deadband, the sharing arrangement is triggered. If a regulatory framework contained an ESM with no deadband, the utility would operate under pure cost-of-service regulation, with no incentive to find cost efficiencies.

ESMs may have a symmetrical or asymmetrical design. Symmetrical ESMs allow a true-up for both under-and over-earning. Asymmetrical ESMs require the utility to share profits exceeding a predetermined threshold with customers, while bearing full responsibility for any earnings shortfalls. Such a design aims to benefit ratepayers by allowing them to participate in efficiency gains without bearing the risk of earnings shortfalls.

Figure 5.3 provides an illustrative example of how a utility's earnings would change under a two-tier, asymmetric ESM. This example assumes that the utility's allowed ROE is set at 10%. The ESM is structured to have a 100-basis point deadband, such that there no sharing occurs for earnings below an ROE of 11%. If ROE exceeds 11%, the utility shares 50% of its earnings between 11% and 12% ROE and 80% of earnings above 12% ROE.[94]

[94] In this example the deadband is established around the adjusted ROE and not the ROE before the adjustment. This is due to the fact that first tier adjustments reduce utilities effective ROE.

Figure 5.3: Two-Tier ESM Over-Earning Example



ESM Example: Eversource Energy

As part of their most recent revenue cap plan, Eversource Energy, an electricity distribution utility, proposed a tiered asymmetric ESM, structure as follows:

- Customers would receive 25% of earnings between 100 and 150 basis points above the authorized ROE.
- Customers would receive 50% of earnings between 150 and 200 basis points above the authorized ROE.
- Customers would receive 75% of earnings exceeding 200 basis points above the authorized ROE.
- No adjustments would be made for earnings below the authorized ROE.

One advantage of this tiered approach, which allows the utility to retain a larger proportion of its earnings just above the allowed ROE, is to facilitate the enhanced cost efficiency incentives of the revenue cap plan while offering protection to customers in case the utility manages to make very large efficiency gains. However, the Massachusetts Department of Public Utilities approved a different ESM, under which customers would receive 75% of all earnings exceeding 100 basis points above the authorized ROE.[95]

ESMs present a good example of an alternative regulation tool that is used to adjust the risk-reward balance of a regulatory framework. ESMs may be preferable in cases where the regulator has less accurate information about the potential for cost reduction and they cannot credibly

[95] Massachusetts Department of Public Utilities. *D.P.U. 22-22*. November 30, 2022

promise to permit exceptionally high or exceptionally low levels of profit.[96] While the use of an ESM can reduce earnings risk for the utility and protect customers from paying rates that lead to unpalatable utility profits, the reconnection of revenues and costs also reduces the incentive power of a PBR plan. Through an ESM refund mechanism, utility customers may end up with a bigger slice of a smaller pie in the long run.

Table 5.12: Recommendations for Earnings Sharing Mechanisms

Earnings Sharing Mechanisms	If the state of Indiana adopts an indexed cap regulatory framework (or a forecasted MYRP), utilities or utility stakeholders may wish to incorporate ESMs to reduce risk. However, if ESMs are adopted, we recommend wide deadbands in order to maintain cost efficiency incentives.

5.1.5.9 Efficiency Carryover Mechanisms (ECMs)

An ECM is a mechanism that allows for a portion of productivity gains to be kept by the utility beyond the end of a PBR term.[97] Over the course of a PBR term, the utility has an incentive to find efficiency gains, but rebasing between PBR generations appropriates these gains (and returns them to consumers) with an updated cost-based revenue requirement. This weakens incentives for the utility to identify and implement efficiency gains in the final years of a PBR term. An ECM is designed to combat these adverse incentives.

Currently, ECMs are not widely used in North American PBR plans.[98] However, theory suggests that economic benefits may be fostered by ECMs. If Indiana opts to pursue indexed cap PBR, stakeholders should carefully consider possible ECM designs.

Table 5.13: Recommendations for Efficiency Carryover Mechanisms

Efficiency Carryover Mechanisms	If the state of Indiana adopts a form of MYRP regulatory framework (or a forecasted MYRP), we recommend exploring Efficiency Carryover Mechanisms as a way to maintain cost efficiency incentives over rebasing periods.

5.1.6 Indexed Cap Summary

Evidence from other jurisdictions suggests that the indexed cap form of incentive regulation may provide benefits to customers in the form of slower rate escalation over time relative to more traditional regulatory structures that do not provide such cost efficiency incentives. Given current pressures on utilities as a result of price inflation, price and revenue caps could provide utilities with a tool to address customer concerns regarding cost control.

[96] David P. Brown and David E. M. Sappington. *Designing Incentive Regulation in the Electricity Sector.* November 2023. p. 10

[97] Alberta Utilities Commission. *Rate Regulation Initiative: Distribution Performance-Based Regulation.* September 12, 2012. p.165.

[98] Not all PBR frameworks include ECMs. For example, the revenue cap plans currently in effect in Massachusetts and Hawaii do not have defined ECMs. While the current FortisBC PBR plan does not contain an ECM, the BCUC has allowed FortisBC to apply for an ECM under a certain set of criteria.

As discussed above, price caps and revenue caps differ in a few important ways. Under a price cap, revenues vary with consumption, which may lead to increased risks relative to a framework that includes revenue decoupling. Under a price cap, declines in consumption could affect revenue and reduce earnings if prices are not set equal to unit costs. Conversely, consumption increases (e.g., because of sales volume growth) can lead to returns beyond the conventionally acceptable range set forth by the regulating body. A revenue cap model, on the other hand, allows the utility to adjust its rates to reflect an indexed level of revenue, rather than prices.

Questions regarding future electricity demand have become increasingly relevant in recent years as distributed generation and energy efficiency efforts continue at the same time as electrification and the growth of data centers. Electrification also drives utility costs, creating cost uncertainties. In the face of this uncertainty, revenue caps may provide stability for utilities over the course of the PBR term. On the other hand, revenue caps may limit the revenue growth required to internally fund the investments required to meet electrification demands. The choice between price and revenue caps depends on various factors, including the specific goals of the regulator, the characteristics of the utility and its service territory, and broader policy objectives such as promoting energy efficiency or renewable energy adoption.

Indexed caps also carry risks, such as the potential for reduced service quality if utilities cut costs too aggressively. To mitigate this, regulators can incorporate quality of service standards and PIMs into the MYRP framework. Other risks include revenue deficiencies over the PBR term, which, because of the rate case stay-out agreement, cannot be remedied in the form of a timely rate case filing. Such financial risks can also be mitigated through the inclusion of additional elements in the PBR framework (Z, Y, and K factors).

Table 5.14 summarizes the common components of indexed cap PBR plans.

Table 5.14: Description of Factors Used in Price and Revenue Caps

Factor	Description
Inflation	The most recent government numbers for the chosen inflation measure.
X Factor	A measure of industry-wide productivity growth.
Stretch factor (Customer dividend)	Adjustment applied to the X factor to share efficiency gains between the utility and its customers.
Z factor (Exogenous cost factor)	Allows rate adjustments for unforeseen, non-controllable events such as natural disasters or major regulatory changes.
Y factor	Allows rate adjustments for recurring costs that utilities cannot control such as transmission charges.
K factor	Provides revenue support beyond I-X for capital expenditures.
Reopeners	Allows for remedying potential problems with the PBR plan before the end of the PBR term.
ESMs	Share earnings that deviate from allowed ROE. Maybe symmetric or asymmetric, with different proportions of sharing and different deadbands.
Efficiency Carryover Mechanism	Strengthens PBR incentives across PBR rebasing periods.

Successful implementation of price or revenue caps can improve the operational efficiency of utilities and generate savings for customers. However, there are inherent challenges to the application of price and revenue caps, particularly in Indiana.

Indiana's utilities are vertically integrated, which makes the application of a single index to all components of the rate (generation, distribution and transmission) challenging. The lumpiness of capital in generation is particularly challenging to account for in pure indexed cap PBR (i.e., a plan without supplemental capital mechanisms). In addition, each utility operates within a different stage of their capital investment cycle, which means some utilities might benefit, while others may struggle, from the capital input trends reflected in the industry productivity factor.[99,100] While some of the challenges of applying price and revenue caps can be addressed through the exclusion of highly variable cost components from the indexed cap, such exclusions would also reduce the benefits that could be derived from an indexed cap approach. Since cost trackers are already in use in Indiana and stakeholders are already familiar with them, some of the utilities' variable cost components could be excluded from the indexed cap if one were implemented.

Table 5.15: Recommendations for Indexed Caps in Indiana

Indexed Caps	Price or revenue caps may be of interest in Indiana because of the potential to improve cost efficiency among the state's IOUs. However, the vertically integrated organization of the state's electric utilities presents practical complications. If the state pursues indexed caps, we recommend a hybrid approach, as follows: • Only the distribution portions of utility operations operate under the indexed cap; and/or • Capital costs should be either forecasted or tracked by a company-specific mechanism; • Adopting the recommendations in Sections 5.1.5.1 through 5.1.5.7.

5.1.7 Real World Indexed Cap Examples

To assist with conveying how indexed caps work in the real world, we present three examples: a price cap from Alberta, Canada, a revenue cap from Hawaii, and a hybrid revenue cap from Massachusetts. These jurisdictions have markedly different characteristics. Alberta's PBR framework regulates all distribution-only utilities in the province with the same I-X formula, wherein each utility operates within a landlocked, meshed transmission grid. In Massachusetts, unlike in Alberta, distribution utilities choose to operate under a customized revenue cap. The Hawaiian utilities are vertically integrated and operate on islands.

[99] Similar concerns are also present when applying price and revenue caps to distribution only utilities, however the vertically integrated structure in Indiana may amplify these challenges.
[100] This can be illustrated with a simple example: if the companies that are included in industry productivity calculation have recently undergone heavy capital investments, the estimated X factor would be lower and would benefit companies that are not pursuing any major capital investments in the near future.

These examples demonstrate indexed caps' relevance for Indiana while showcasing their practical implementation. The Hawaii example is relevant due to its vertically integrated utilities, similar to Indiana's. Alberta provides a price cap model that has been refined over multiple PBR iterations. The Massachusetts example demonstrates how capital may be separated from operations and maintenance costs, which could inform Indiana's consideration of indexed approaches applied to specific cost components.

5.1.7.1 Price Cap Example: Alberta Electric Distribution Utilities

In 2023 Alberta Utilities Commission (AUC) approved its third generation PBR (PBR3) plan for the 2024 to 2028 period, which maintains price cap regulation for electric distribution utilities. Alberta utilities' allowed change in prices is described by the following formula:

$$\%\Delta P = (I - X) + Y + Z + K^1 + K^2 \qquad (5.2)$$

Where:

%ΔP = allowed change in capped price
I = inflation factor
X = productivity factor
Y = recurring flow through items, collected through Y factor rate adjustments
Z = one-time exogenous adjustments
K^1 *= Type 1 capital recovered through capital trackers*
K^2 *= Type 2 capital recovered through K-bar*

The X factor is informed by the results of total factor productivity studies for the electric distribution industry and is further adjusted by a stretch factor.[101] Mechanically, the stretch factor increases the X factor (which reduces the allowed price increases).

AUC has also established asymmetric two-tiered ESM:

- For earnings between 200 and 400 basis points above the approved return on equity, utilities retain 60% of the excess.
- For earnings exceeding 400 basis points above the approved return on equity, utilities retain 20% of the excess.

5.1.7.2 Revenue Cap Example: Hawaiian Electric Company (HECO)

The Hawaiian Electric Company operates under a five-year revenue cap plan, based on the following formula:

$$Revenue_t = Revenue_{t-1} * (1 + I - X - CD) + EPRM + Z \qquad (5.3)$$

Where:

$Revenue_t$ = allowed revenue in year t
I = inflation, (equal to GDP-PI)
X = productivity index (set equal to zero percent)

[101] See Jeffrey I. Bernstein and David E.M. Sappington, "Setting the X Factor in Price-Cap Regulation Plans," *Journal of Regulatory Economics*, Vol. 16, 1999, p. 9.

CD = consumer dividend (set equal to 0.22 percent)
EPRM = costs allowed to be recovered under the Exceptional Projects Recovery Mechanism
Z = costs associated with exogenous, one-time events

The formula adjusts revenues each year by the percentage change in GDP-PI (the Gross Domestic Product Price Index) minus a pre-determined stretch factor.[102] Each year, depending on circumstances, the utility's allowed revenue may be adjusted by several additional components, including cost trackers, a Z factor, PIMs, and a capital recovery mechanism.

The Hawaiian utilities have cost trackers that allow for the recovery of costs pertaining to fuel and purchased power, pensions, demand-side management, renewable energy infrastructure program. These costs are recovered outside of the allowed revenue that is adjusted by the inflation-based revenue cap. The Z factor provides the utility with an opportunity to review and recover prudently incurred costs that address events beyond the control of the utility.[103]

The PBR framework also contains a provision for additional revenue related to capital expenditures. In particular, the Exceptional Project Recovery Mechanism ("EPRM") is a -mechanism that allows the utility to file for cost recovery of projects that meet certain criteria. It provides recovery of allowed revenues for the net costs of these approved "Eligible Projects" placed in service during HECO's five-year revenue cap period, provided that cost recovery is not already covered by another effective recovery mechanism.[104] Eligible Projects include infrastructure necessary to connect renewable energy projects, projects that encourage clean energy choices or conservation, utility scale generation and storage, grid modernization, and other similar projects.

5.1.7.3 Hybrid Revenue Cap Example: National Grid

Massachusetts Electric Company and Nantucket Electric Company, each doing business as National Grid, operated under a total revenue cap formula from 2019 to 2024, similar to the cap adopted by the Hawaiian Electric Company. However, beginning in 2025, the revenue cap was modified to treat O&M and capital expenses separately; an anticipated surge in necessary capital investment, driven in large part by the Electric Sector Modernization Plan for Massachusetts, was expected to leave the company with insufficient revenue during the 2025-2029 period. To resolve this issue, the company proposed bifurcating its revenue requirement into revenue associated with O&M expenses and a capital revenue requirement. The former would be escalated by an index formula each year, while the latter would be recovered from annual capital revenue requirement filings. This proposal was accepted by the Department of Public Utilities in Massachusetts in 2024, with the O&M revenue requirement escalated using the following formula:

[102] Although the PUC referred to HECO's revenue cap as an "I-X" revenue cap because an X factor was considered, the X factor was arbitrarily set to equal zero in the final decision. For this reason, the Hawaii revenue cap is not truly an "I-X" revenue cap, as it does not incorporate industry productivity.

[103] HECO's exogenous costs must exceed a threshold of $4 million to be eligible for Z factor cost recovery. This is equivalent to 0.14% of the company's total allowed revenue.

[104] Hawaii Public Utilities Commission. *In the Matter of the Application of Hawaiian Electric Company, Inc. For Approval to Commit Funds in Excess of $2,500,000 (excluding customer contributions) for the PZ.005125 – Kahe-Waiau 138 kV Undergrounding Project and to Recover Costs through the Exceptional Project Recovery Mechanism. Decision and Order No. 38451 Docket No. 2021-0086*. p62.

$$OM\ Revenue_t = OM\ Revenue_{t-1} * (1 + I - X - CD) + Y + Z \quad (5.4)$$

Where:

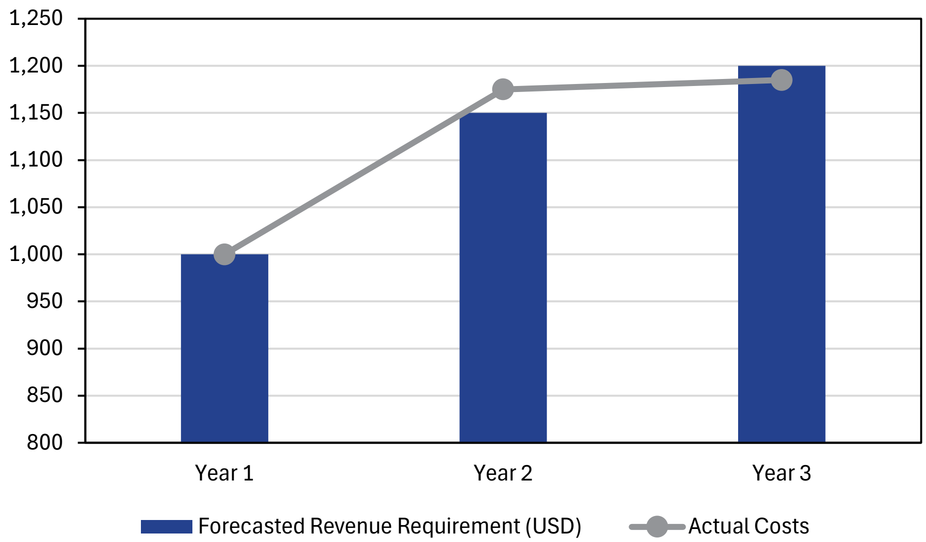
OM Revenue$_t$ = O&M revenue requirement in year t
I = inflation, (equal to a weighted average of a regional employee cost index and the producer price index for electric utilities)
X = partial productivity index (set equal to 0.21 percent)
CD = consumer dividend (set equal to 0.4 percent)
Y = incremental operating expenses arising from increased capital expenditures
Z = costs associated with exogenous, one-time events

5.2 Forecasted Multi-Year Rate Plans

A forecast approach offers an alternative to the indexed cap MYRP. Utilities might implement a forecasted MYRP in a number of different ways, but the key differentiating feature of forecast MYRPs relative to indexed caps is that whereas price caps and revenue caps rely on industry average adjustments that are exogenous to the company, a forecasted MYRP relies on the company's own forecasts of its revenue requirement over a period of time. The forecasted MYRP approach establishes the utility's revenue requirement each year of the PBR term at the initial plan filing. These forecasts typically include estimates of future operating expenses, capital investments, depreciation, taxes, and allowed rate of return, as well as projected sales and number of customers served.

Figure 5.4 depicts a prototypical three-year forecasted MYRP. Under this plan, the utility's actual costs may vary year-to-year relative to its forecasted revenue. In Year 1, realized costs are closely aligned with the forecasted revenue requirement. This is expected because forecasts are generally more accurate for costs incurred in the near future than for those further in the future. In Year 2, actual costs exceed the forecasted revenue requirement. In this case, the utility will need to manage under a revenue shortfall, as the revenue requirement cannot be adjusted during the MYRP term. In the final year of the MYRP, the example utility's forecasted revenue exceeds its actual costs. In this case, the utility is able to keep its profits.

Figure 5.4: Illustrative Example of Forecasted MYRP



Forecasted MYRPs provide more oversight and control over the utility's revenues during the PBR term, both for the utility and for the regulator, relative to indexed caps. One key advantage of the forecasted revenues approach is that it can provide a more accurate reflection of the utility's expected costs and market conditions compared to indexing caps. This can be particularly beneficial in periods of significant change, such as when major infrastructure investments are planned or when the utility sector is undergoing substantial transformation. A utility facing cost growth substantially different from the rest of the industry might therefore find forecasted MYRPs feasible, even when indexed caps are not workable.

However, there are risks and potential drawbacks. One drawback is that the forecasting process may involve extensive negotiations, evaluations, and input regarding the projected revenue requirement from various stakeholders, including consumer advocates and industry experts. This process may be more expensive and time-consuming than a traditional cost-of-service rate case. However, as with indexed caps, the initial administrative costs would be outweighed by the reduction in rate case frequency and cost efficiency gains under a well-designed plan.

A risk with forecasted MYRPs is that, typically, under a forecasted MYRP, the company may only collect the forecasted revenues—regardless of the costs incurred. While this risk imposes some cost efficiency incentives on the firm, allowing it to earn profits for better-than-expected cost management, the firm could incur losses if its costs exceed allowed revenues. Similarly, companies may seek to benefit from information asymmetry by inflating their forecasted revenue requirement in order to mitigate risk or improve profits. To address concerns that costs may diverge from allowed revenues over the PBR term, regulators often incorporate mechanisms to share the risk of forecast errors between the utility and its customers. For example, in Great Britain, utilities operating under the "Revenue using Incentives to deliver Innovation and Outputs" (RIIO) framework pay a forecasting penalty that increases as actual costs deviate from the forecast.[105] Another approach might include earnings sharing provisions that require the utility to return a portion of any excess earnings to customers if actual costs turn out to be lower

[105] Decision – RIIO-ED2 Final Determinations Finance Annex, p. 132.

than forecast.[106] Similarly, some plans may include reopener clauses that allow for rate adjustments if actual costs deviate significantly from the forecast.

Another risk, which also exists under indexed cap PBR, is that cost cutting may occur not because of gains in efficiency, but rather, at the expense of service quality. To protect consumers from the utility cutting spending at the expense of service quality or planned capital expenditures, the regulator may introduce PIMs or impose rules requiring capital to be placed into service before related revenues can be collected by the company.

A Note on Future (or Forward) Test Years

As discussed in Section 3.3, Indiana's IOUs are permitted to file future or "forward" test year revenue requirements. A forward-looking test period can be used to set a utility's revenue requirement on the basis of projected data for a 12-month period beginning no later than 24 months after the date on which the utility petitions the commission for a change in its rates and charges. This form of cost-of-service regulation using projected data has qualities that overlap with forecasted MYRPs. Both require forecasted cost information, and both can be used to provide a timely alignment of rates with costs.

A difference between regulation under future test years and forecasted MYRPs is that typically forecasted MYRPs have a longer time horizon, between three and five years.

As with any regulatory construct, the likelihood of success for forecasted MYRPs depends on the details. The forecast approach also may result in higher or lower cost efficiency incentives depending on the plan design. If the utility can influence the forecast to be overly generous, it may reduce the pressure to cut costs. Conversely, if the forecast is too stringent, it could put undue financial pressure on the utility, potentially compromising service quality or necessary investments.

The forecasted revenues approach can be more complex and resource-intensive than other MYRP methods, requiring significant regulatory oversight and expertise. However, when implemented effectively, it can provide a balanced framework that aligns utility incentives with regulatory objectives while accounting for the specific circumstances and challenges facing the utility over the plan period. Table 5.16 provides our recommendations with regard to forecasted MYRPs.

[106] While ESMs may be effective in addressing forecast errors, they reduce the incentive for utilities to efficiently manage their expenditures.

Table 5.16: Recommendations for Forecasted MYRPs in Indiana

Forecasted MYRPs	Forecasted MYRPs may be a feasible incremental step toward PBR for Indiana because of the overlap of this kind of framework with current ratemaking practices in the state. Forward test years and phase-in rates are already approved for Indiana's IOUs, and these mechanisms have much in common with forecasted MYRPs. If done correctly, forecasted MYRPs have the potential to improve utility cost efficiency incentives and reduce the regulatory burden of frequent rate cases. If the state pursues forecasted MYRPs, we recommend: • Allow the IOUs to file tailored MYRPs, rather than imposing a common, rigid framework upon each utility. • Forecasted MYRPs may include elements discussed in Section 5.1, regarding indexed caps. For example, exogenous cost factors (Z and Y factors) may be included, as well as reopener provisions.

5.2.1 Real World Forecasted MYRP Example: Duke Energy Carolinas

On October 13, 2021, a bill authorizing PBR for electric utilities was signed into law by the Governor of North Carolina.[107] This change permits utilities in North Carolina to submit PBR applications as part of their general rate case. Such applications could include revenue decoupling mechanisms, PIMs, ESMs, and forecasted MYRPs.

Duke Energy Carolinas' (DEC) most recent general rate case included a PBR plan with many of these elements. DEC proposed and currently operates under a three-year forecasted MYRP with an asymmetric ESM that distributes all earnings excess of 50 basis points above the authorized return on equity to customers. The plan also contains a reopener, which states that if DEC's weather-normalized earnings fall 50 basis points below the authorized rate of return on equity, DEC may file a rate case, thereby leaving the MYRP. Revenue increases during the MYRP are determined based on forecasted capital spending throughout the rate period and are capped at 4% of the first-year revenue requirement, excluding capital spending projects placed in service during the first rate year.

Arguably, North Carolina's approach to MYRPs offers some cost containment incentives. The reopener and ESM limits the benefits utilities can derive from efficient cost reductions. However, the plan may also facilitate other benefits, such as less frequent rate applications and timely cost recovery.

[107] *G.S. 62-133.16*

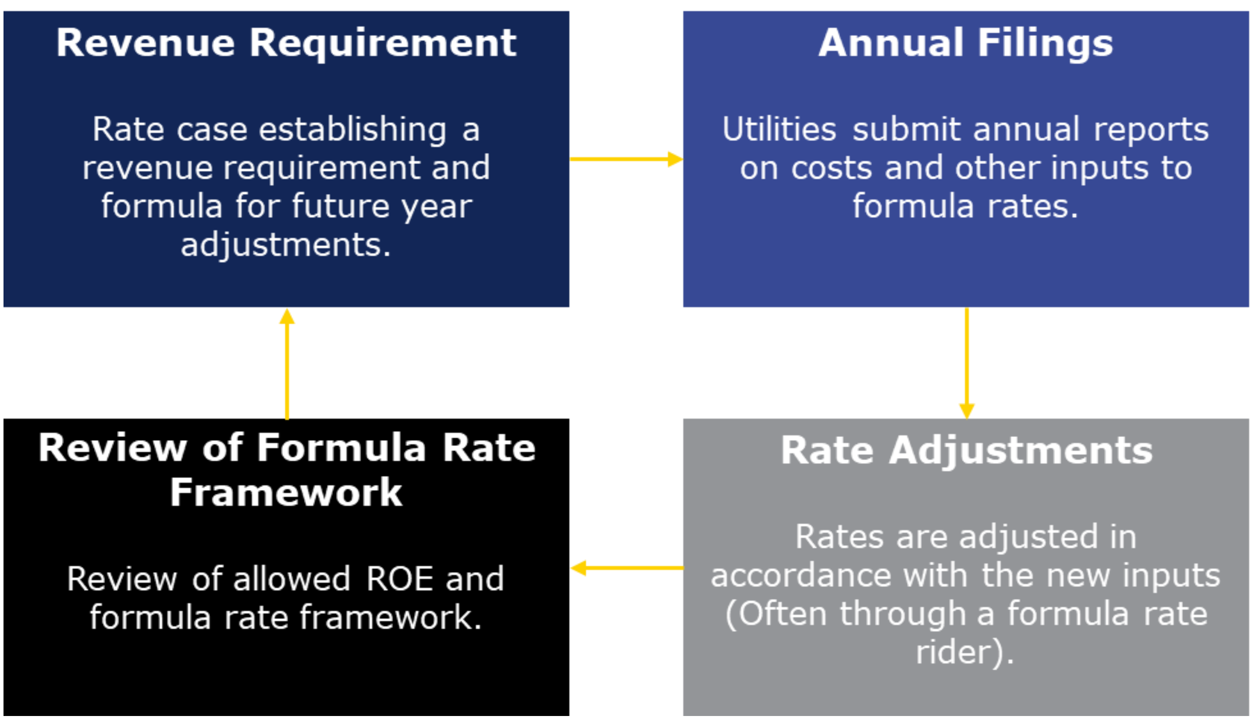
5.3 Formula Rates

We include formula rates in this discussion for the sake of completeness as an alternative form of regulation, but formula rate plans are not considered to be a form of PBR. Formula rates are used by many electricity transmission companies that file rates with the Federal Energy Regulatory Commission, as well as some retail utilities in the southeastern United States.

Formula rate plans establish a formula based on company earnings information to automatically adjust rates, typically on an annual basis. Because of the name, formula rates might be confused with indexed cap plans, which also rely on a formula. However, the two forms of regulation are very different. Unlike indexed caps, formula rate plans set prices based on company specific data rather than industry-wide information. This means that rates are set on a cost-to-serve basis and do not have the incentive properties of indexed caps. In fact, because of the low efficiency incentives associated with formula rate plans, such plans are not considered to be a PBR tool.

Figure 5.5 provides a simplified overview of how formula rates are established, reviewed and updated. The specifics of formula rates differ between jurisdictions, but the formula rates are generally established for multiple years and require annual filings by the utilities to report their costs and earnings. At the end of the pre-determined formula rate period, the formula rate framework is reviewed and updated.

Figure 5.5: Simplified Formula Rate Application Process



The advantage of formula rate plans is that they are designed to provide a transparent and predictable way to update rates without the need for frequent, full-scale rate cases. The formula usually incorporates various components of the utility's costs, such as operating expenses, capital investments, return on equity, and sometimes performance metrics, as well as allowed rate of return. Each component of the formula is clearly defined and may be subject to specific rules or limits. For example, the allowed rate of return might be adjusted annually based on changes in financial market conditions. Formula rate plans also have the advantage of providing timely cost recovery for utilities. As actual costs change, rates can be adjusted relatively quickly, reducing regulatory lag and potentially lowering the utility's financial risk.

One of the primary drawbacks of formula rates is that they often allow utilities to pass increased costs directly to customers. This mechanism reduces the utility's incentive to pursue cost reductions or efficiency improvements. It also may make it more difficult to assess projects that are recovered through rates between rate applications. As such, formula rate plans require careful design and ongoing monitoring to ensure they serve the interests of both the utility and its customers throughout the MYRP period.

Table 5.17 provides our recommendations regarding formula rate plans.

Table 5.17: Recommendations for Formula Rate Plans in Indiana

Formula Rate Plans	We do not currently recommend Indiana to pursue formula rate plans. However, if IOUs face major, lumpy investments and the frequency of rate cases becomes a problem, this is an option that could be considered.

5.3.1 Real World Formula Rate Plan Example: Entergy Louisiana

Entergy Louisiana's rates have been set through a Formula Rate Plan (FRP) since 1995. In Entergy Louisiana's most recent rate case, the formula rate plan has been extended for 2024-2026 period.[108]

Entergy Louisiana operates their formula rates through a FRP Rider. The FRP regulates electric rates by establishing an approved Evaluation Period Cost of Equity (EPCOE) and then requiring prospective rate changes if Entergy Louisiana's test year operating revenues produce an earned return on equity either higher or lower than the approved EPCOE plus or minus a 40-basis point earnings bandwidth (deadband). For a given year of the FRP, if the Company's earned return on equity falls outside the deadband, the FRP will adjust rates to the edge of the deadband.

Each year Entergy Louisiana is required to file an FRP evaluation report, which is based on Entergy Louisiana's actual earnings for the prior 12 months. Any revenue adjustments and changes to rates through the FRP rider are reflected in the evaluation report.

There are several categories of costs that the current FRP allows Entergy Louisiana to recover outside the mechanism described above. Some exceptions include recovery of certain investments in capacity and transmission, extraordinary costs; and certain MISO-related costs and revenues.

[108] Louisiana Public Service Commission. *Order U-36959*. September 13, 2024.

5.4 MYRP Summary

Utility MYRPs consist of several categories: indexed caps, forecast-based rates, and formula rates, though hybrid approaches combining elements of these categories are also common. A hybrid MYRP might blend indexed caps with forecast adjustments or incorporate other forms of cost-of-service information, like capital trackers. Because the specific details of each plan vary between jurisdictions, and even between utilities within jurisdictions, no two MYRPs are exactly alike. These differences arise from different utility spending plans, industrial organization (e.g., vertically integrated vs. distribution-only), regulatory objectives, risk tolerance, and precedent.

MYRPs: Allocating Risks Between Customers and Shareholders

The allocation of risk between customers and shareholders depends on the MYRP design. The more a utility's own costs influence allowed rates charged during the MYRP term, the more risk is shifted from the shareholders to the utility's customers. A utility under indexed cap PBR generally bears more risk than a similar utility under forecasted MYRPs. The latter regulatory framework allows the utility to estimate its revenue needs over time, while the former structure only allows annual changes according to an index that is outside of the control of the utility.

Section 5.1 detailed numerous tools that could be employed to control the risk of cost volatility. For example, a price cap plan with no exogenous factors would place substantial risk on the utility to maintain cost control, while customers face very little risk, as prices are capped according to industry-wide trends. The addition of cost trackers (e.g., Y factors or Z factors) shifts exposure to input cost volatility from the utility to its customers. Other tools, like reopeners and ESMs further reduce a utility's risk exposure. However, these tools reduce the cost efficiency incentive power of the regulatory framework.

MYRPs balance risk and incentives. If a plan assigns more risk to the utility, the potential to earn higher profits increases, which improves the incentive power of the plan. Lower risk regulatory frameworks, including traditional cost of service regulation, generally result in lower cost efficiency incentives.

The design of a MYRP has implications for utility incentives. Whereas indexed caps generally provide enhanced cost efficiency incentives, formula rates have relatively low-cost efficiency incentives—even lower than traditional regulation. At the same time, for utilities with particularly lumpy capital investment, a pure indexed approach may simply not be workable given the utility's spending plan. The goal of improved cost efficiency is, ultimately, to provide customers with benefits in the form of lower rates without negatively affecting safety and reliability. To achieve this goal, incentives must be paired with considerations of feasibility. If a proposed MYRP framework is out of line with the spending forecast of the utility, it will not provide benefits to customers in the long run, no matter how strong the plan's theoretical incentives might be.

Throughout this section, we have reviewed the benefits and challenges of different forms of MYRPs. Each approach presents a different balance of priorities. Table 5.18 provides a summary of these benefits and challenges.

Table 5.18: Benefits and Challenges of Approaches to MYRPs

Approach	Benefits	Challenges
Price Caps	• Provides an annual rate adjustment equal to the rate of inflation minus industry productivity over the MYRP term • Utility can increase revenue and profits through sales growth • Provides cost efficiency incentives	• May result in intervenor resistance to automatic rate increases not tied to costs • Does not protect the utility against sales declines
Revenue Cap + Decoupling	• Provides an annual rate adjustment equal to the rate of inflation minus industry productivity, plus customer count growth over the MYRP term • Protects utility against sales declines • Provides cost efficiency incentives	• May result in intervenor resistance to automatic revenue increases • Does not allow for revenue increases beyond the I-X+G adjustment, even if sales increases occur
Forecasted MYRP	• Provides utility with opportunity to request revenues according to expected costs • Relatively straightforward to implement • Protects utility against sales declines	• Intervenor resistance to automatic revenue increases • Requires more regulatory scrutiny over spending forecasts • Strength of cost efficiency incentives not well established in economics literature
Formula Rates	• Reduces rate application frequency • Aims to keep revenues and costs closely aligned	• Has the lowest cost efficiency incentives (and is not considered to be PBR) • May face criticism related to the evaluation of projects between rate cases.

Given the industry structure of Indiana's investor-owned utilities, we believe that a major overhaul to the regulatory structure may be unnecessarily disruptive. A pure indexed cap approach, which would adjust utility rates or revenues according to the exogenous factors of inflation and industry productivity, may be infeasible despite the potential cost efficiency benefits. This is because the state's IOUs have substantial generation and transmission assets with large, uneven investment requirements that are difficult to control for or index.

Such an approach may fail to adequately account for these fluctuations in investments, leading to mismatches between cost recovery and investment needs, which can create financial strain and impede future investments. Additionally, because utilities operate at different stages of their capital investment cycles at different times, some may benefit from an indexed cap while others could face revenue deficiencies over the PBR term. Given these challenges, a hybrid approach that excludes capital-intensive components from the indexed cap may be more suitable if price caps or revenue caps are of interest.

As explained in Table 5.19, forecasted MYRPs may be a better option. Regulatory tools currently in place in the state of Indiana, like phased in rates and forward test years, provide some overlap with this approach. Forecasted MYRPs are more common than indexed caps among vertically integrated utilities.

Table 5.19: Recommendations for MYRPs

Recommendations for MYRPs in Indiana	Given that the top concern among stakeholders relates to affordability and cost control, MYRPs that offer cost efficiency incentives may be worth consideration for Indiana's IOUs. As indexed cap PBR frameworks raise feasibility issues for vertically integrated utilities that operate in Regional Transmission Operator (RTO) regions, we do not recommend pure price caps or revenue caps at this time. Hybrid indexed caps may be feasible on a utility-specific basis, wherein each utility may propose a framework that provides incentives while providing sufficient revenue support over a rate case stay-out period. As such, we recommend allowing IOUs to voluntarily file hybrid PBR plans. Stakeholders also stated that incremental change was preferred to major changes to the state's regulatory framework. Forecasted MYRPs could provide an incremental change that offers improved cost efficiency incentives and reduces rate case frequency. We recommend allowing IOUs to voluntarily file three- or four-year forecasted MYRPs.

6 PERFORMANCE INCENTIVE MECHANISMS (PIMS)

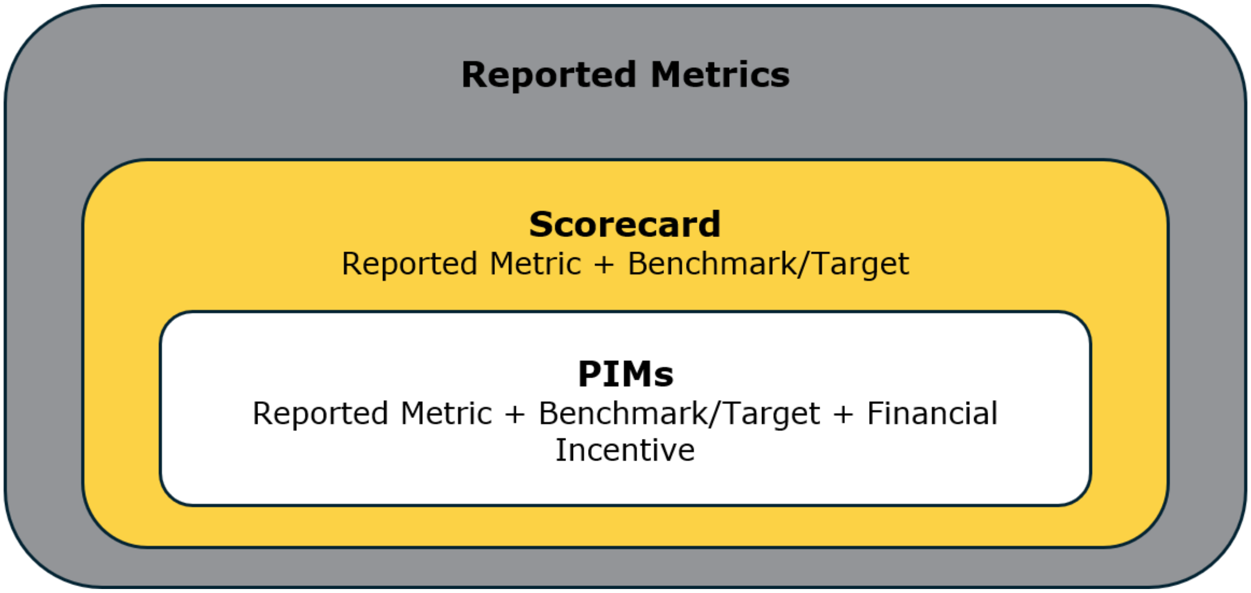
[This section provides in-depth description of PIMs and their application and provides information that addresses Indiana Code § 8-1-2.5-6.5 (c) (3), (4), (5), (6) and (7).]

PIMs constitute the category of PBR tools focused on incentivizing certain utility outputs. These mechanisms are designed to align utility performance with regulatory and public policy goals by providing financial incentives for achieving specific performance targets. PIMs are distinct tools from "reported metrics" and "scorecard metrics," which do not employ financial incentives.

Most utilities publish metrics aimed at providing information on service quality. Utilities, regulators, and other stakeholders benefit from these metrics. Utilities can use performance metrics to better understand areas where improvement or investment is needed. Regulators and other stakeholders benefit through increased transparency into the health of the utility, which can help with establishing policy. The regulator may also better understand certain revenue needs outlined in the utility's rate application if it has insight into the utility's performance history. Deteriorating performance in particular categories might warrant enhanced investment. For customers, scorecards can contextualize the service they receive as individuals within the broader system, which can help with developing sensible consumer advocacy and expectations. These metrics provide a common assessment point between all parties when evaluating utility performance.

As depicted in Figure 6.1, scorecard metrics add a layer of accountability to reported metrics by introducing benchmarks or targets. Establishing such benchmarks can assist with evaluating whether the utility meets its expected service quality. However, scorecard metrics do not involve financial rewards or penalties. PIMs differ from reported metrics and scorecards in the use of financial incentives. For each performance area, regulators establish specific metrics, performance targets, and a system of rewards and penalties. When utilities exceed the established targets, they may earn additional revenue. Conversely, if they fail to meet the targets, they may face financial penalties or reduced returns. Whether a PIM administers penalties or rewards—or both—depends on the design of the PIM.

Figure 6.1: The Hierarchy of Reported Metrics, Scorecards, and PIMs[109]



The subject of performance metrics often arises in discussions of indexed cap or forecasted MYRP frameworks because of a theoretical possibility that the cost-cutting incentives of revenue or price caps will lead to service quality degradation. Metrics can provide counter-pressure to the incentive to cut costs during a PBR stay-out period by providing incentives to maintain superior performance or prevent poor performance.[110] Although a review of industry literature does not indicate any link between PBR incentives and reduced service quality, performance metrics are seen as a mechanism for monitoring the quality of utility service at the same time that the company faces cost-related efficiency incentives.

6.1 Definition of PIMs

A PIM is an annual revenue adjustment mechanism that ties financial incentives to the achievement of pre-defined benchmarks or targets. PIMs can be reward-only, penalty-only, or symmetric, meaning they could result in both a reward and a penalty. Typically, PIMs operate by adjusting a utility's ROE, though in some cases a pre-determined dollar value is used for a penalty or reward.

Reported metrics, which already exist in Indiana, provide information on various dimensions of service quality but do not directly affect a utility's revenue. These metrics could be transformed into PIMs by affixing revenue recovery to the outcomes of these metrics. Many reported metrics, however, do not align well with the criteria for PIMs, as outlined in Section 6.3.

To be considered a PIM, the utility must have a measurable target, and it must be possible to recognize the achievement of this target using publicly available information at the end of each year when rates are set for the subsequent year of the PBR term. In addition, the financial penalty or reward associated with achievement of (or failure to achieve) the target must be

[109] This figure was adapted from: Decision and Order 37507. Hawaii Public Utilities Commission. Docket No. 2018-0088. p. 155.
[110] Whited, Utility PIMS – A Handbook, 2015, p. 16.

known in advance. PIM penalties or rewards will be applied to rates each year as a rider, adjusting revenues according to performance in the most recent completed year.

6.2 Considerations for Designing PIMs

A clear set of criteria for the development of PIMs has not been widely adopted across jurisdictions that operate under PBR. However, several jurisdictions have developed principles and guidelines for PIM design. For example, the New York Public Service Commission (NYPSC) stated that PIMs should accomplish one of two objectives: (1) encourage the achievement of new policy objectives; or (2) counter implicit negative incentives that the state's ratemaking model provides.[111]

One question about the design of PIMs is whether to make the financial incentive a reward, a penalty, or financially symmetric — meaning that the PIM offers a reward for positive achievement and a penalty of sub-par achievement. An approach to answering this question is to offer a reward if the utility has not been expected to produce the output in the past, since the cost is not reflected in rates, and a penalty if the utility is already expected to provide the output. For example, if a certain level of reliability is expected, a SAIDI or SAIFI PIM could be penalty only. For new policy objectives, like faster home connections or Non-Wires Solutions, achievement could be tied to reward-only PIMs.

General criteria for designing a new PIM may include that the PIM:

- Does not cause a large increase in administrative burden for utilities, stakeholders, or the regulator;
- Uses existing data measured by Indiana IOUs;
- Is consistent with/takes into consideration other initiatives on-going in Indiana;
- Tracks outcomes that utilities can control;
- Has rewards and penalties that are proportionate to the value provided by the achievement of a PIM target (accounting for costs of administering a PIM);
- Is unambiguous, easily interpreted, and objectively verifiable;
- Addresses policy goals or priorities that are not adequately addressed in existing regulation tools/policies;
- Maintains confidentiality of customer level data.
- Provides benefits to ratepayers.

The PIMs from other jurisdictions reviewed for this study were based on information that is publicly available and does not include confidential customer information. Best practice for collecting data from electricity suppliers would suggest relying on data that conforms to this approach. However, to the extent that confidential data might be required to set a particular PIM, the IURC has experience handling sensitive data.[112]

[111] Interestingly, the NYPSC rejected arguments that PIMs should be restricted to items under the utility's direct control or strong influence, stating that an outcome-oriented approach was the most effective route.
[112] See, for example, the Indiana Utility Regulatory Commission *2024 Annual Report*, p. 52.

These proposed criteria are in line with PIM design principles and guidelines in other jurisdictions such as Rhode Island, Massachusetts and D.C.[113]

> **PIMs Proposed by National Grid in Rhode Island[114]**
>
> In 2018, the Public Utilities Commission of Rhode Island did not accept six out of seven PIMs proposed by Narragansett Electric Company d/b/a National Grid. The Commission evaluated National Grid's PIMs using the following eleven questions:
>
> 1. Does the incentive promote the realization of new consumer and societal benefits?
> 2. Does the incentive promote behavior that the utility otherwise would not take?
> 3. Is there a clear nexus between the metric and the expected benefits?
> 4. Is there a clear, stated reason why the incentive is needed to achieve each specific objective?
> 5. Is the incentive designed to promote superior utility performance and significantly advance the expected benefits as efficiently as possible?
> 6. Is the incentive designed so that customers receive most of the benefit?
> 7. Is the incentive designed to grant increasing levels of rewards to the utility for higher levels of performance?
> 8. Will the design and implementation of the incentive be completely transparent and fully document and reveal inputs and methodologies to ensure no duplication of incentives across various ratepayer funded programs?
> 9. Is it possible to compare the cost of achieving the metric to the potential benefits?
> 10. What objectives does this incentive promote?
> 11. Are these opportunities for the company to earn multiple incentives for attaining the same objective?
>
> For example, the commission rejected the PIM on "CO_2 Electric Vehicle PIM," as the company may already propose a performance incentive that rewards emission reductions within the existing energy efficiency program plan (see Question 2). All six rejected PIMs were approved as track-only metrics with no financial incentive attached.

Notably, PIMs generally do not aim to address overall utility cost efficiency. This is because PIMs are primarily concerned with the production of utility *outputs*, while MYRPs like indexed caps confront the matter of efficient inputs.

A question regarding the adoption of PIMs in the state of Indiana is whether PIMs will be imposed on the IOUs, or whether the IOUs may propose their own individual PIMs through a regulatory proceeding. A regulator might impose a standard set of PIMs on utilities in order to achieve a policy objective that utilities might not pursue voluntarily. The drawback, however, is that the same PIM may affect different utilities in different ways. One utility may face conditions that make the achievement of certain benchmarks easier than for a utility operating under different

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[113] Goldenberg et al. *PIMs for Progress: Using Performance Incentive Mechanisms to Accelerate Progress on Energy Policy Goals, Rocky Mountain Institute*. p72-75.

[114] Rhode Island Public Utilities Commission. *Report and Order No. 23823 issued to National Grid and the Parties accepting the Amended Settlement Agreement*. p30.

conditions. Certain PIMs may cause a proportionally larger administrative burden for small utilities compared to large utilities.

6.3 Challenges to the Implementation of PIMs

There are several issues with providing financial incentives to utilities on the basis of performance metrics. First, utilities operate in a complex macroeconomy which can provoke service quality shocks exogenous to management's control. Penalizing a utility for failing to meet targets due to uncontrollable factors, through a PIM, can render the regulatory framework's incentives ineffective. It is also likely that stakeholders would protest paying financial reward to a utility for achieving goals merely through chance. Policymakers should take care to set PIMs on the basis of metrics that are reasonably within the control of the utility.

Proposed Exclusions from a Reliability PIM

As an example of a PIM design that has attempted to reflect controllable performance, consider the following reliability PIM. This PIM includes six qualifiers to the System Average Interruption Duration Index (SAIDI).

In 2024, ATCO Utilities, gas and electric distribution utility in the province of Alberta, Canada, proposed a penalty-only reliability PIM based on SAIDI for its electric operations. For the purposes of calculating a financial penalty for this PIM, ATCO Utilities proposed to adjust its SAIDI measure for the following items:

1. Interruptions that are resolved within 5 minutes or less;
2. Private customer outages;
3. Planned outages;
4. Loss of external supply;
5. Public safety directed outages;
6. Major event days.

These adjustments assist with focusing the PIM penalty on reliability shortfalls within the control of management.

Second, incentive pressure from PIMs may operate with a lag, as management learns how to better find efficiencies or as new investments take time to provide intended benefits. For this reason, some metrics may have limited ability to capture management performance efforts. For example, plant additions aimed at improving reliability may take over a year to implement—and thus, a utility may face penalties even after making system upgrades aimed at avoiding such penalties. In such cases, measures observed over longer time horizons may be more suitable.

Third, performance metrics have costs. Poorly designed metrics may have large data requirements that are not easily fulfilled, leading to inefficiencies and costs that outweigh the benefit of the information they might provide. One of the costs of establishing performance metrics is determining the appropriate thresholds above or below which a utility will be rewarded or penalized, as well as the magnitude of the reward. This may require expert evaluation, and even with such expert evaluation, a fourth challenge is that the proper quantum of reward or penalty will likely be an estimate. Measurement error can result in imbalanced or unfair PIMs.

A fifth issue in the creation of performance metrics is "single issue regulation". A metric may obfuscate a problem if it misrepresents the intended goal of the metric, or it may give rise to unintended consequences as the utility optimizes to maximize earnings. For example, if a utility creates a single metric to measure customer service quality by recording the average number of minutes a customer waits on the phone, on hold, the company may become very good at answering calls quickly but neglect other avenues of customer communication like website interaction. A crucial point in the construction of a service quality measurement plan is that the scorecard should consider individual elements as well as the mission as a whole. If the utility focuses on each metric in isolation, some metrics may result in competing incentives. On the other hand, too many metrics can lead to a higher regulatory burden that counteracts the PBR framework's efficiency goals.

Whether or not the utility operates under PBR, management and regulators must balance the costs and benefits of performance metrics, lest the utility suffer from an excessive number of goals, or a set of goals that place excessive pressure on the company's operations. Table 6.1 contrasts the challenges of operating under PIMs with the advantages.

Table 6.1: Advantages and Challenges of PIMs

ADVANTAGES	CHALLENGES
Alignment with Public Policy Goals • Targeted incentives allow regulators to promote important policy goals • Can shift the focus from capital investment to measurable outcomes.	**Design Complexity** • Quantifying performance outcomes and setting appropriate rewards/penalties. • Timely access to metrics.
Improvements in efficiency • Incentives to achieve specific performance goals. • Protects against service quality declines while considering economic efficiency.	**Accounting for External Factors** • Uncontrollable external factors may impact performance metrics. • Mechanism must balance fairness with administration simplicity.
Flexibility and Transparency • Increases transparency in utility performance through measurable metrics. • Incentive mechanisms can be changed to adjust to changing market conditions	**Unintended Consequences** • Poor design can lead to attention toward specific goals to the detriment of service that is not rewarded/penalized. • Risk of gaming or manipulation by utilities.

6.4 How to Set Reward and Penalty Targets

A PIM administers a reward (or penalty) to the utility for the achievement of (or failure to achieve) certain pre-determined targets. The determination of these targets should be based on economic principles and data. There are three general categories of methods for setting targets: (1) based on the utility's own past performance; (2) based on the utility's performance in comparison to its peers; and (3) based on quotas or levels set by policy. Whether to use a particular one of these methods depends on the type of PIM, data availability, and the details of the policy objectives the PIM aims to address.

6.4.1 Thresholds Based on Utility's Own Past Performance

A utility's own past performance has been used to set PIM benchmarks in other jurisdictions.[115] A utility may set a baseline using average historical performance, perhaps over five or ten years of history. A threshold might then be set equal to one or two standard deviations from this average. A threshold set according to mean and variance information assumes that past performance reflects a reasonable range of performance in the future. It also assumes that a penalty or reward is warranted when performance deviates sufficiently from historical average performance.

One reason for using a utility's own past performance is that cross-company comparisons may not accurately reflect its unique operating conditions. Different utilities operate in different physical environments, are at different stages of their capital cycle, have different systems, and serve different customer mixes. All of these factors may affect the utility's performance relative to its peers. Applying rewards or penalties on the basis of factors like these, which are beyond the control of company management, may not be just and reasonable.

Another advantage of the historical performance approach therefore is simplicity and data availability. When comparing companies, the PIM threshold may require a regression model or some other means of controlling for factors driving differences between firms. This introduces the possibility of disagreements regarding technical design, as well as data requirements that could be burdensome. Simple historical averages mitigate this problem.

However, using the utility's own data in setting performance thresholds controls for some factors, but not all. Past performance may differ from the future as a result of system changes, even within the same utility. For example, system upgrades might improve reliability and reduce the standard deviation of reliability measures. Conversely, changing climate conditions may reduce reliability relative to the past.

Another possible shortfall of this approach is that a utility's past performance may be better or worse than peer companies for reasons within management's control, and as a result, this method could set penalty or reward threshold levels above or below what is reasonable. For example, if a utility works hard to maintain a high level of reliability over time, and then a SAIDI PIM is imposed, it may be punished for good historical performance in the form of challenging threshold levels. Similarly, if the utility knows that future PIM thresholds will be based on current performance, management has some ability to manage SAIDI levels for future benefits. In other words, the PIM becomes *endogenous* to company performance, rather than *exogenous.*

6.4.2 Thresholds Based on Comparison to Peers

Setting PIM thresholds in relation to peer companies involves comparing a utility's performance on specific metrics with the average performance of similarly situated peer utilities. For example,

[115] See, for example, Hawaii.

a threshold may be set based on the current year industry average and standard deviation values, rather than the utility's own historical average.

There are several advantages to making comparisons across peer companies. First, thresholds based on cross-sectional peer performance reflect current conditions and the experience of customers served by utilities regionally. Peer-based thresholds may be more relevant because of the use of contemporaneous data, rather than data from five or ten years in the past. Second, if the goal is to provide similar service quality for all customers, regardless of utility-specific conditions, the peer benchmarking approach is a more relevant measure. Third, whereas utility-specific thresholds may involve some endogeneity, peer-based thresholds are strictly exogenous. This means that a utility that performs well over time relative to its peers is not punished for its good performance.

Drawbacks to the peer benchmarking approach include increased complexity and the possibility that benchmarks are not set relative to a utility's operating conditions. Performance benchmarking across utilities requires more data and the use of more technical methods, increasing the complexity and potential administrative burden of the approach.

6.4.3 Thresholds Based on Quotas or Policy

In some cases, industry standards may set PIM thresholds irrespective of utility historical data or sector-wide cross-sectional data. For example, if a regulator has established a goal of connecting new DER customers within a certain number of days, a utility's past performance, or the performance of its peers in making these connections, may not be relevant. In such cases, the regulator may consider data to frame the threshold, even if the data is not explicitly used to calculate a specific threshold value.

This approach may be used because of data limitations. It may also be the case that the regulator deems empirical information less relevant for the purposes of determining thresholds, as the goal is to achieve a set threshold regardless of current or past utility performance. A drawback, however, is that stakeholders may dispute thresholds not based on concrete data.

6.5 PIMs Summary

Utility outputs span more dimensions than just kilowatt-hours of electricity. Output dimensions also include reliability, safety, system efficiency (i.e., load factor), connection time, and customer service. Increasingly outputs also may involve addressing environmental policy goals like DER connections, the incorporation of EV charging stations, and energy efficiency. Utilities may not have a natural incentive to prioritize certain non-traditional outputs, or perhaps stakeholders agree that enhanced attention to traditional outputs is required. PIMs can offer an economically efficient means of achieving objectives or remedying deficiencies by attaching financial incentives to the achievement of pre-defined standards.

Generally, regulators and utilities institute PIMs after identifying specific, targeted policy goals related to utility outputs. This involves establishing metrics, defining achievement thresholds, and setting financial rewards or penalties. Whereas transitioning from a traditional form of cost-of-service regulation to an MYRPs may entail substantial changes for the utility, stakeholders, and the regulator, PIMs have the advantage of being relatively compatible with existing utility remuneration frameworks. For example, a company could add a DER connection PIM to its existing framework, change nothing else, and continue its operations with a new performance-based incentive aimed at achieving a policy goal.

However, the implementation of PIMs requires careful design to ensure they effectively drive desired outcomes without unintended consequences.[116] For example, if a PIM incentivizes improvements in reliability but does not address customer service, utilities may shift resources from customer service to reliability improvements, leading to deterioration in customer service. Another challenge is determining the appropriate dollar value for rewards and penalties that will motivate utilities while ensuring the financial burden on ratepayers remains justifiable and proportional to the benefits. Other key considerations include selecting metrics that are meaningful, measurable, and within the utility's control, and setting achievable targets. We have provided criteria in Section 7.2 that can guide the development of successful PIMs.

PIMs: Allocating Risks Between Customers and Shareholders

As explained in Section 6.2, PIMs should be calibrated with accurate data and priced according to marginal costs and marginal benefits. PIMs should also apply to areas of utility performance that management can control. Following these criteria ensures that utilities are not unduly rewarded or penalized, while ensuring that customers receive benefits at the price they value those benefits.

Regulators and utilities can also design PIMs with additional guardrails. For example, caps on potential rewards and floors on potential penalties can mitigate risk by protecting customers from excessive rate increases due to overly generous incentives and safeguards shareholders from financial instability due to extreme penalties for events beyond reasonable control.

The process of designing PIMs can incorporate risk mitigation efforts. By soliciting input from stakeholders, PIM designers can obtain help with identifying blind spots. Building a periodic review and adjustment process into the design can also assist in addressing changing circumstances, as well as the evolving needs of customers and the utility.

While the utilities in Indiana do not operate under PIMs as defined in this section, many of the tools leveraged by the IURC share similar features with target-oriented PIMs. For example, the IURC currently has the authority to investigate and penalize utilities for unsatisfactory performance. While the IURC has not formally established target metrics and associated rewards or penalties that follow a PIM structure, the IURC has in the past made ad-hoc adjustments to utility's allowed ROE during rate cases citing utility performance or management issues as a reason for downward adjustment.[117] In addition, Indiana's DSM initiatives share similarities with PIMs, as Indiana utilities are rewarded for DSM and energy efficiency initiatives that are cost-effective and provide a net benefit to the customers. As well, IOUs obtain a financial incentive for

[116] The Public Utilities Regulatory Authority (PURA) of Connecticut is considering the adoption of PIMs (Docket 21-05-15RE02) as part of their ongoing investigation of PBR. During this process PURA has hosted multiple technical meetings and has invited feedback on the key considerations and challenges for PIMs implementation. The overall PBR investigation was initiated in 2021, and the PIMs specific investigation was launched in 2024.

[117] Indiana Utility Regulatory Commission, *Cause No. 43526 and Cause No. 44576*. The IURC considered utility performance in selecting the allowed ROE.

utilities to engage in opportunity sales in the wholesale market that would benefit Indiana customers.

Considering the findings of this section, along with feedback from stakeholders as outlined in Section 8, we recommend that the IURC allow the state's IOUs to file PIMs as part of future rate applications, to be assessed on a case-by-case basis. In addition, we recommend that before instituting any mandatory PIMs, or any PIMs that apply to all utilities, the IURC develop a set of specific policy goals that might be addressed by PIMs and meet with stakeholders to discuss potential benefits and drawbacks of attaching financial incentives to related metrics.

Table 6.2: Recommendations for PIMs in Indiana

Recommendations for PIMs in Indiana	1. We recommend that the IURC allow the state's IOUs to file PIMs as part of future rate applications, to be assessed on a case-by-case basis. 2. We recommend that before instituting any mandatory PIMs, or any PIMs that apply to all utilities, the IURC develop a set of specific policy goals that might be addressed by PIMs and meet with stakeholders to discuss potential benefits and drawbacks of attaching financial incentives to related metrics. Studies may be required to set performance thresholds and the dollar value of financial incentives.

6.5.1 Real World PIM Example: New York

New York utilities have been subject to the Reliability Performance Mechanism (RPM) and the Customer Service Performance Mechanism (CSPI) for many years. These mechanisms were initially created to prevent excessive spending cuts under MYRPs.[118] The RPM measures overall distribution system reliability, including criteria such as frequency and duration of outages, remote network monitoring system performance and timely replacement of damaged poles. The CSPI measures the company's customer service quality using a broad number of indices. The utilities face negative revenue adjustments if certain performance thresholds across the RPM and CSPI are not met.

In addition to the state's existing PIMs, the Renewing Energy Vision (REV) framework also introduced specific earning opportunities based on utility performance, called "Earnings Adjustment Mechanisms" (EAMs), which is synonymous with PIMs. While the Commission decides the EAM opportunity areas, each utility can propose their own performance incentives within these identified areas. Table 6.3 summarizes the EAM opportunity areas and examples of approved EAMs for New York utilities.

[118] New York State Department of Public Service, Staff Report and Proposal. *Reforming the Energy Vision*. *Case 14-M-0101*. April 24, 2014. p48.

Table 6.3: EAMs in the State of New York[119,120,121]

EAM Area	Example	Details of approved EAMs
System Efficiency (Mandatory)	Electric System Peak (Con Edison 2020)	Incent the Company to deliver New York Control Area coincident electric system peak reduction. Metric: actual weather normalized coincident system peak in MW Reward: The company will receive 3 to 8 basis point ($4.356 to $11.615 million) if targets are met. Penalty: None
	Locational System Relief Value Load Factor (Con Edison 2020)	Improve load factor of more constrained portions of the distribution system that are not current or likely Non-wires Alternatives areas. Metric: load factor Reward: The company will receive 1 to 5 basis point ($1.452 to $7.259 million) if targets are met. Penalty: None
	DER Utilization (Con Edison 2020)	Incent the company to work with DER providers and expand use of DER. Metric: annualized MWh produced or discharged from incremental DER Reward: The company will receive 3 to 10 basis point ($4.356 to $14.518 million) if targets are met. Penalty: None
Energy Efficiency (EE) (Mandatory)	Sharing the Savings (Con Edison 2020)	Reduce unit costs for the Company's combined electric and gas EE portfolio by reducing the unit cost of lifetime energy savings Metric: unit cost savings relative to the baseline unit cost times non-Low to Moderate Income EE savings Reward: 30% of the savings Penalty: None
	Deeper Energy Efficiency Lifetime Savings (Con Edison 2020)	Achievement of Energy Efficiency (EE) savings from EE measures beyond lighting and behavioral measures. Metric: Lifetime energy savings (in LMMBtu) provide by deeper EE measures in the Company's entire EE portfolio. Reward: The company will receive 2 to 11 basis point ($2.904 to $15.970 million) if targets are met. Penalty: None
Interconnection (Mandatory, but eliminated later)	No actual EAM was implemented.	Each utility negotiated the basis for this EAM in their rate cases, but targets were not established.

[119] State of New York Public Service Commission. *Order Adopting a Ratemaking and Utility Revenue Model Policy Framework. Case 14-M-0101*. May 19, 2016. p61-65.
[120] Consolidated Edison Company of New York Case 19-E-0065 & 19-G-0066 Joint Proposal. October 16, 2019.
[121] Central Hudson Gas and Electric Corporation Case 17-E-0459 & 17-G-0460 Joint Proposal. April 18, 2018.

EAM Area	Example	Details of approved EAMs
Decarbonization of end uses	Beneficial Electrification	Incent Con Edison to support the adoption of electric vehicles and heat pumps to decrease carbon emissions. Metric: Lifetime CO_2 emissions reductions provided by annual incremental beneficial electrification technologies. Reward: The company will receive 2 to 10 basis point ($2.904 to $14.518 million) if targets are met. Penalty: None
Customer Engagement	Customer Participation in Time of Use rates (Central Hudson 2018)	Incent the Company to increase customer participation in Voluntary Time of Use (VTOU) rates. Metric: percentage of residential customers that sign up for VTOU rates. Reward: The company will receive $32,500 if participation reaches 1.51% (minimum target) and $162,500 if participation reaches 2.74% (maximum target). Penalty: None

6.5.2 Real World PIM Example: Hawaii

Hawaii Electric Company (HECO) reports a broad set of metrics, with dozens of different metrics currently active.[122] Like Indiana, many of these metrics are merely reported, rather than PIMs offering financial incentives, though the companies have eight PIMs currently in effect. Under the current UR model, HECO must balance different objectives of its UR model as it strives to achieve metrics goals while attempting to find cost efficiencies. Its success in this pursuit remains an open question—as the cost of administering more metrics may deteriorate cost efficiencies, even as other goals of the PBR framework may be achieved.

A working group appointed by the PUC assisted with the conceptualization and design of Hawaii's current PIMs. Comments and proposals were also submitted by HECO and several other stakeholders, which the PUC considered in its final decision. Given the energy transition goals underpinning the state's PBR framework, many of the approved PIMs pertain to incorporating renewables and DERs onto the grid.

HECO's PIMs aim to achieve both energy transition goals and affordability for customers. To accelerate renewable energy adoption, the Renewable Portfolio Standard-Accelerated (RPS-A) rewards utilities for exceeding clean energy goals, incentivizing faster integration of renewable sources like solar and wind. To facilitate the energy transition from the perspective of grid management, the PUC implemented PIMs that address challenges arising from a changing grid. For example, the Interconnection Approval PIM encourages faster approval processes for connecting new renewable energy systems to the grid.

The Grid Services PIM is designed to promote DER asset effectiveness, as well as grid investment efficiency, by incenting the expeditious acquisition of Grid Services capabilities from DERs. Grid Services include "Load Build"—in which entities provide energy to the grid when generation is needed—and "Load Reduction"—in which entities reduce usage to relieve capacity constraints.

[122] Hawaiian Electric Company. *Performance Scorecards and Metrics.*

Grid Services also includes Fast Frequency Response (FFR).[123] Traditionally, FFR services were provided by spinning reserves, which are backup generators that can quickly ramp up power production. More recently, however, FFR services might be obtained from battery storage systems and "smart inverters" that quickly adjust power output based on grid frequency. This PIM existed prior to the 2021 implementation of Hawaii's revenue cap framework, but was modified to include load reduction, as the PUC cited a "critical need for peak reduction" across Hawaii's service territories.[124]

To encourage affordability and equity, the Low-to-Moderate Income Energy Efficiency PIM pushes utilities to collaborate with energy efficiency programs, helping low-income residents participate in the energy transition by offering them ways to manage their energy use and potentially save money.

Table 6.4 presents HECO's current PIMs, describing the metrics, rewards, penalties, and desired outcomes.

Table 6.4: List of PIMs in Hawaii[125]

PIMs	Details
RPS-A (Renewable Portfolio Standards)	Incent Hawaiian Electric to accelerate the achievement of its Renewable Portfolio Standards goals. Metric: Companies' annual compliance with the RPS. Reward for exceeding the RPS target: $20/MWh in 2021 and 2022, $15/MWh in 2023, and $10/MWh for the remainder of the MRP. Penalty: as prescribed in the RPS, the Commission has increased the potential reward in the early years of the MYRP to encourage further acceleration of renewable development associated with the upcoming retirements of fossil-fueled plants and support post-COVID economic recovery. Regulatory outcomes: DER Asset Effectiveness, Customer Engagement, Interconnection Experience, Cost Control, Affordability, Grid Investment Efficiency, and GHG Reduction.
Grid Services PIM	Incent the expeditious acquisition of grid services capabilities from DERs. Metric: kW capacity of grid services acquired. Reward: companies will receive a one-time award on per kW basis depending on the grid services acquired and the service territory it will serve. Penalty: None. Regulatory outcomes: Promote DER Asset Effectiveness and Grid Investment Efficiency.

[123] Hawaii Public Utilities Commission. *DPS Phase 3 D&O Summary.*

[124] Hawaii Public Utilities Commission. *Order 38429.* p60.

[125] Hawaii PIMs References:

- Public Utilities Commission of the State of Hawaii. *Docket No. 2018-0088, Decision and Order No. 37507.*
- Public Utilities Commission of the State of Hawaii. *Docket No. 2018-0088, Decision and Order No. 37787.*
- Public Utilities Commission of the State of Hawaii. *Docket No. 2013-0141, Decision and Order No. 34514.*

PIMs	Details
Interconnection Approval PIM	Metric: Number of business days it takes the companies to complete all steps within the companies' control to interconnect DER systems <100kW in size. Three tiers of targets with financial rewards and penalties to encourage incremental improvement. Maximum annual reward is $3 million for all companies, calculated on a target revenue basis. Maximum annual penalty will be set for $900,000 for all companies, calculated on a target revenue basis. Regulatory outcome: Interconnection Experience.
Low-to-Moderate Income Energy Efficiency PIM	Incent collaboration between Hawaiian Electric and Hawaii Energy to deliver energy savings for low- and moderate-income customers. Metric 1: Residential Hard-to-Reach Energy Savings Beyond Hawaii Energy's Target. Reward structure: $/kwh reward factor times the amount of kWh energy verified savings. Metric 2: Residential Hard-to-Reach Peak Demand Reduction Beyond Hawaii Energy's Target Reward structure: $/kW reward factor times the amount of kW peak demand verified savings Metric 3: Affordability & Accessibility program Customers Served Beyond Hawaii Energy's Target Reward structure: $/customer reward factor times the verified number of customers served. Total reward capped at $2 million annually. Regulatory outcome: Customer Equity, Customer Engagement, Affordability
Advanced Metering Infrastructure ("AMI") Utilization PIM	Incent acceleration of the number of customers with advanced meters enabled to support time-varying rates and next generation DER programs. Metric: percentage of total customers with advanced meters delivering at least two of the three benefits ("Customer Authorization", "Energy Usage Alert", "Program Participation"). Maximum annual reward: $2 million. Regulatory outcome: Customer Engagement, DER Asset Effectiveness, Grid Investment Efficiency.
SAIDI/SAIFI PIMs	(Penalties only) Maximum revenue exposure: 20 basis points on earnings. Regulatory outcome: Reliability. The utility (HECO) proposed symmetric award/penalty, while the consumer advocate supports penalty only. The HECO companies proposed expressing maximum financial incentive amounts for the PIMSs based on percentage of T&D revenue requirements, while the consumer advocate proposed financial incentive amounts based on basis points on earnings. The commission finds using "basis points on earnings" provides a more direct and meaningful context for considering the appropriate magnitudes of the financial incentives.

PIMs	Details
Call Center PIM	Metric: the percentage of calls answered within thirty (30) seconds. Maximum revenue exposure: +/- 8 basis points on earnings. Regulatory outcome: Customer Engagement.

The HECO companies have had mixed success in meeting PIMs objectives. In 2022 and 2023, HECO exceeded the PIM connection time threshold for its Interconnection Approval PIM. HECO achieved its renewable generation threshold for the RPS-A PIM in 2022, but not in 2023. None of the three HECO IOUs achieved the SAIFI, Call Center, or AMI Utilization PIMs thresholds in 2022 or 2023. In some cases when PIM thresholds were not achieved, HECO cited forces beyond the Company's control as presenting obstacles to achievement of the PIMs.[126]

[126] "Notice Transmittal to Update Target Revenue through the Major Project Interim Recovery Adjustment Mechanism, Exceptional Project Recovery Mechanism, and Calculation of 2022 Performance Incentive Mechanism and Shared Savings Mechanism Financial Incentives," Hawaiian Electric Companies, June 1, 2023.

7 OTHER TOOLS IN ALTERNATIVE REGULATION

[This section addresses Indiana Code § 8-1-2.5-6.5 (c) (8).]

This section covers other alternative regulations tools that do not neatly fall under MYRPs or PIMs, but that are sometimes used in other jurisdictions.

7.1 Time Varying Rates and Demand Response

Alternative rate designs can assist with achieving regulatory goals and improving system efficiency. According to Ind. Code § 8-1-2.5-6, the IURC has the authority to approve time-varying and alternative electricity rates, including options such as time-of-use (TOU) or off-peak pricing, critical peak pricing, variable peak pricing, and real-time pricing. However, the use of TOU rates in Indiana is limited, with only two utilities – I&M and Duke Energy Indiana – offering TOU rates to their customers.

Time-varying electricity rates allow utilities to charge prices that better reflect the actual costs of providing electricity at different times. During high-demand periods, electricity provision becomes more expensive for utilities for two primary reasons. First, higher wholesale energy costs emerge as peak demand periods require activating more expensive generating units. These "peaking" plants often have higher operational costs and are only economically justified during periods of high demand. Second, the electrical grid's transmission and distribution systems must be built to handle maximum coincident demand peaks, ensuring reliable service even during the highest usage periods. Higher peak demand on the system tends to drive inefficiencies as peaking plants are expensive to build, but do not need to operate most hours of the year.

By implementing time-varying rates, utilities may achieve cost efficiencies. When consumers shift usage away from peak times in response to higher rates, the system requires less overall peak capacity. Lower peak demands can delay or eliminate the need for expensive transmission and distribution infrastructure upgrades. Additionally, smoother demand patterns reduce strain on the electrical system, potentially reducing the likelihood of outages. Peak demand reduction might also provide environmental benefits by reducing reliance on the least efficient, more polluting peaking generation units. Time-varying rate structures aim to provide consumers with economic signals that align with the true costs of electricity provision, encouraging more informed energy usage that benefit both individual consumers and the system as a whole.[127]

Demand response programs provide dynamic price signals to customers, and aim to provide similar benefits to customers. All five major IOUs in Indiana currently operate or have in the past operated demand response programs. These include residential demand response programs, such as smart thermostat programs that allow adjustment of customers' thermostats during peak demand events, AC cycling or water heater shut-off programs, as well as critical peak pricing programs with increased peak hour prices during events to incentive customers to shift

[127] TOU pricing improves cost alignment between utility expenses and customer charges, even when customer behavior remains unchanged. Well-designed TOU rate structures ensure that the costs customers pay more accurately reflect the actual expenses incurred by utilities to provide service during specific time periods.

their electricity usage to non-event hours. Non-residential customers are able to participate in emergency demand response programs.

Indiana customers might benefit from a more widespread adoption of time varying rates. Static TOU rates could be a first step for those IOUs that currently do not offer any TOU rates to their customers. The specific design of TOU rates may differ depending on the price signals the utility wants to send their customers. However, there's some evidence suggesting that shorter time-of-use periods with higher peak to off-peak price ratios provide better incentives for customers to shift their usage.[128,129] Shorter peak-periods allow more flexibility for customers to shift their demand, while higher peak to off-peak ratios provide a stronger financial incentive for customers to shift their usage. Generally, time varying rates require advanced metering within each utilities' service territory.

7.2 Capital Trackers or Project Pre-Approval

Cost of service regulation with regulatory lag can create issues for timely cost recovery, particularly for large capital projects. Under traditional regulation, rate cases set rates according to a utility's embedded costs, but costs associated with new projects are not recovered in base rates until the conclusion of the next rate case. This lack of timely cost recovery can cause hesitation by utilities in making large capital investments. To provide more stable and timely cost recovery, capital trackers that recover revenue on an annual basis have been implemented in many jurisdictions.

Capital trackers can be applied to utilities operating under MYRPs, as well as by or by utilities regulated by traditional rate case regulation as in the case of Indiana utilities. Capital trackers can reduce the regulatory lag for utilities and increase the willingness of utilities to invest in critical infrastructure. However, capital trackers could also lead to capital over-investment and reduce utilities' incentive to control costs.

As noted in Section 3.3.1, Indiana has already implemented capital trackers (for example, in the form of TDSIC) in addition to other expense trackers.

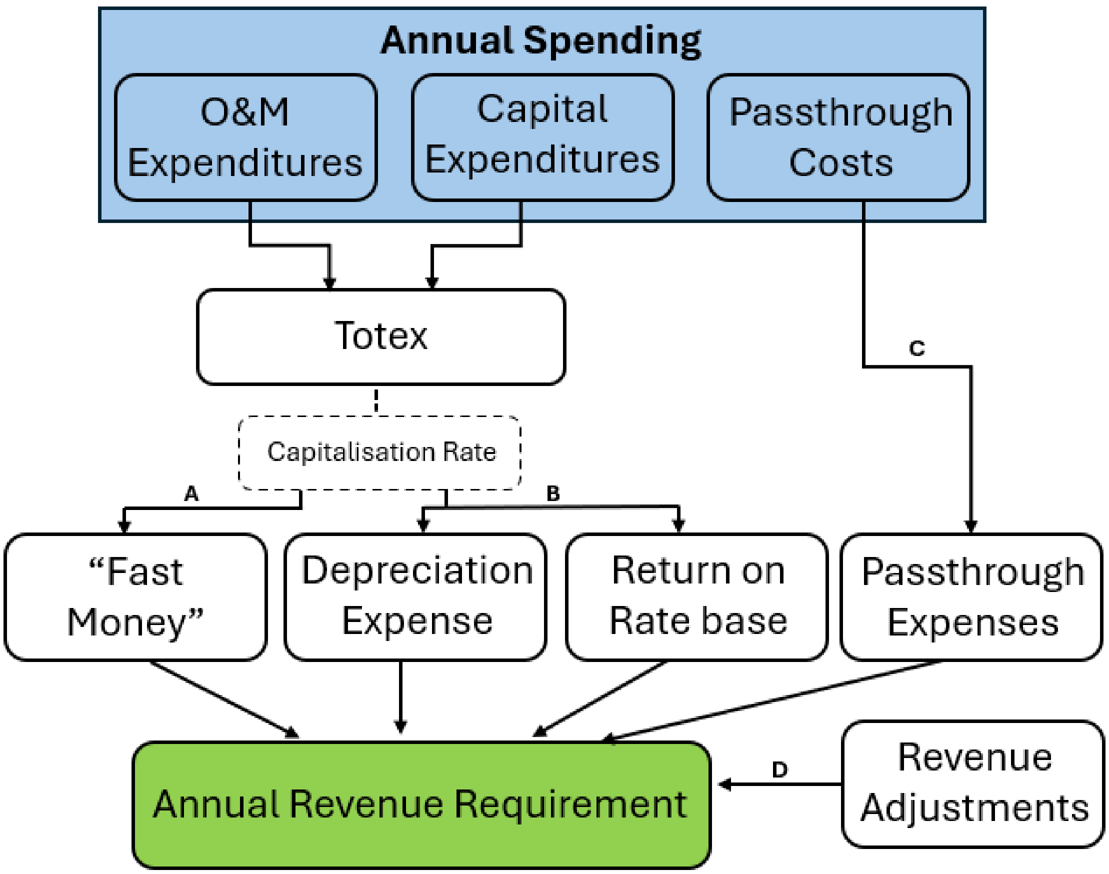
7.3 Totex

Under the "totex" ratemaking approach, distributors obtain a return on total expenditures (totex), which contains elements of both capital spending (capex) and operating spending (opex). The totex approach to setting returns differs from the traditional approach to setting utility returns, in which only capital expenditures earn a return. The totex approach attempts to counter-balance a perceived incentive for utilities to exhibit a capital bias in spending, since capital spending accompanies an allowed return.

[128] David Littell and Joni Sliger. *Time-Varying Rates in New England: Opportunities for Reform.* October 2020.
[129] Peak to off-peak ratio is the price of electricity during the peak hour divided by the price of electricity during an off-peak period. For example, if a utility charges $0.22 per kWh during peak hours and $0.11 per kWh during off-peak hours, the peak to off-peak ratio would be 2 ($0.22/$0.11).

Under the totex ratemaking approach in Great Britain, utility totex is divided into "Slow Money" and "Fast Money" at a predetermined capitalization rate. "Slow Money" is capitalized over time, incorporated into the annual depreciation expense, like capex in the traditional approach. The remainder of totex spending, called "Fast Money", is incorporated into the allowed revenue as an expense, like opex in the traditional approach.[130] Figure 7.1 illustrates the totex approach to developing a revenue requirement used in Great Britain.

Figure 7.1: Revenue Requirement under Great Britain's RIIO-ED2



A: Fast money is the portion of totex that is expensed each year. The portion is determined by the capitalisation rate.
B: The portion of totex not considered "fast money" is capitalized.
C: Passthrough costs such as taxes, tree trimming, and many other expenses are expensed each year.
D. Additional revenue requirement components, such as Output Delivery Incentives, are included in allowed revenue.

The totex approach can also be coupled with an earning sharing mechanism to encourage cost efficiency. In Great Britain, the regulator, Ofgem, set ex ante totex allowances for the utility during the term of each utility's MYRP. A sharing factor called the Totex Incentive Mechanism determines companies' exposure to under or overspends compared to the totex allowances. Totex ratemaking approach has been adopted in Great Britain and Italy as a component of utility

[130] "RIIO-ED2 Final Determinations Core Methodology Document," Ofgem, 30 November 2022.

regulation. Some jurisdictions (e.g., New York and Hawaii) in the US have considered adopting a totex approach, but it is not currently in use in the United States.

7.4 Revenue Decoupling

7.4.1 Defining Revenue Decoupling

Revenue decoupling is a regulatory mechanism used in the electric utility industry to separate a utility's revenue from its sales volume. Traditionally, utility profits were directly tied to the amount of electricity sold, creating an inherent incentive for utilities to promote increased energy consumption. Decoupling breaks this link, allowing utilities to recover their fixed costs and earn a fair return on investment regardless of fluctuations in electricity sales.

The primary purpose of decoupling is to align the financial interests of utilities with broader energy efficiency and conservation goals. By removing the disincentive to promote energy efficiency, decoupling allows utilities to support and implement energy-saving measures without fear of revenue loss. This regulatory approach aims to create a more sustainable and environmentally friendly energy sector while ensuring the financial stability of utility companies.

Decoupling typically involves setting a revenue target for the utility based on its fixed costs and authorized rate of return. If actual revenues fall short of this target due to reduced energy consumption, the utility is allowed to adjust rates to make up the difference. Conversely, if revenues exceed the target, rates are adjusted downward to return the excess to customers. This mechanism helps to stabilize utility revenues and reduces the financial risk associated with fluctuations in energy demand, while also protecting consumers from potential over-charging.[131]

Is Revenue Decoupling a Form of PBR?

Revenue decoupling mechanisms could be classified as a form of PBR, but this is not universally accepted. If PBR entails emulating the competitive market outcome by correcting for any market failures, then revenue decoupling mechanisms can be used to achieve this objective. (For instance, the regulator might worry customer consumption deviates from the social optimum because customers don't internalize the negative externality of environmental impacts.) In any case, revenue decoupling mechanisms are often included in PBR frameworks, so we include a discussion here for completeness.

7.4.2 Revenue Decoupling in Practice

Revenue decoupling mechanisms can be implemented in various ways, tailored to specific regulatory environments and utility structures. These approaches aim to balance the needs of utilities, consumers, and regulatory objectives. One common method allows utilities to adjust rates each year based on the total revenue requirement established during the rate case, such that sales volumes ultimately do not affect realized revenue. This approach ensures that the

[131] It is common for regulators to set a cap to limit price changes from decoupling within a given year to minimize fluctuations.

utility can recover its fixed costs regardless of sales, which may fluctuate as a result of exogenous factors like weather.

An alternative approach is revenue-per-customer decoupling. This method is particularly useful in environments with declining customer bases. It prevents remaining customers from shouldering an unfair burden when the overall customer count decreases. By setting a fixed revenue amount per customer, this approach maintains fairness in cost allocation across the consumer base.

Regulators may also choose to apply decoupling selectively to certain cost categories. For instance, decoupling may be applied to distribution costs while excluding fuel costs. This selective application recognizes that some costs are more volatile or directly tied to consumption than others, allowing for a more nuanced regulatory approach. Regulators may also establish a cap on rate increases from revenue adjustments. When caps are applied, some regulators may allow excess unrecovered amounts to be carried forward to future periods, while others may not. These variations allow regulators to fine-tune the balance between utility financial stability, consumer protection, and energy efficiency incentives.

Figure 7.2 shows adoption of revenue decoupling for gas and electric utilities across the United States. Yellow regions indicate revenue decoupling for both gas and electric utilities, while grey indicates no revenue decoupling is in effect.

Figure 7.2: Revenue Decoupling in the United States[132]

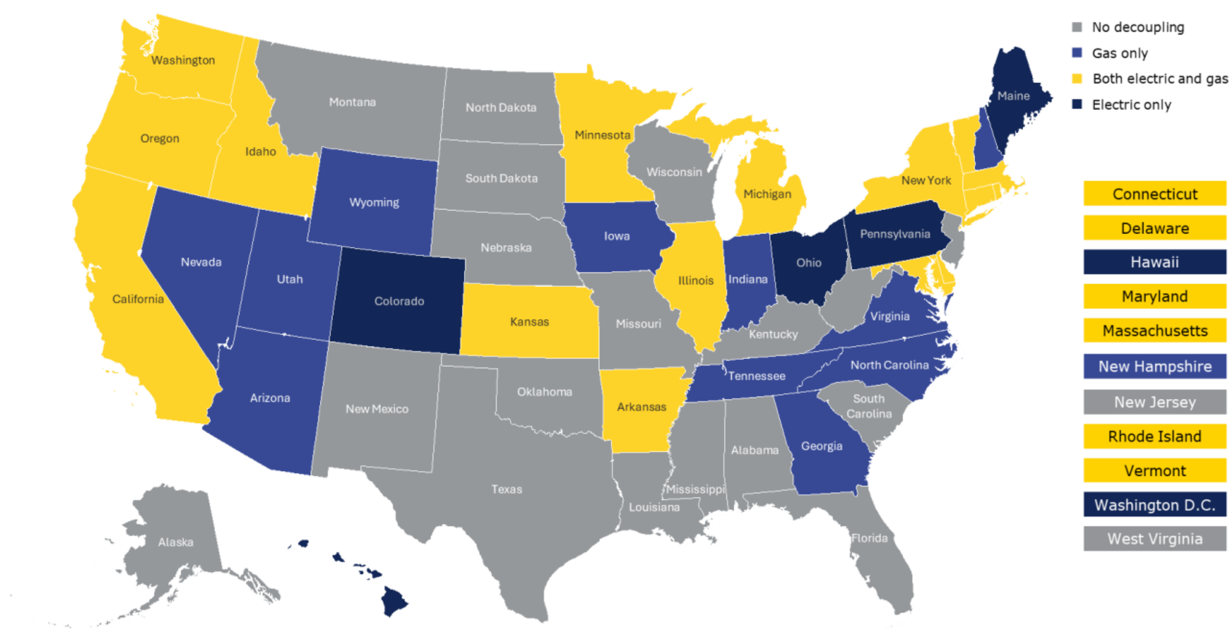


Table 7.1 provides a summary of the advantages and challenges of revenue decoupling. Revenue decoupling was originally designed to remove the disincentive to promote energy conservation by allowing a utility to collect its revenue requirement even if sales volumes decline. Additional benefits include revenue stability and the possibility of less frequent rate cases. Challenges

132 Data for this figure from "Performance-Based Regulation: Harmonizing Electric Utility Priorities and State Policy," by Daniel Shea, *National Conference of State Legislatures*, April 2023.

include rate volatility, as customer rates must be adjusted each year as prior year sales volumes fluctuate.

Table 7.1: Advantages and Challenges of Revenue Decoupling

ADVANTAGES	CHALLENGES
Energy Efficiency • Removes disincentive to promote energy conservation.	**Rate Volatility** • With annual decoupling adjustments rates are likely to change between rate cases
Reduced Frequency of Rate Cases • In changing sales environments utilities would be able to recover	**Complexity** • Decoupling can make utility rates and regulation more complex, potentially reducing transparency.
Revenue Stability for Utilities • Decoupling reduces utility's reliability on sales volumes.	

Given the state's existing LRAM, additional revenue decoupling is not likely to be necessary for Indiana's IOUs. Table 7.2 provides a summary of our recommendations.

Table 7.2: Recommendations for Revenue Decoupling

Revenue Decoupling	Indiana's IOUs already operate with a Lost Revenue Adjustment Mechanism, which shares some properties with revenue decoupling mechanisms. If stakeholders agree that the LRAM is reasonable, we recommend maintaining this approach with no changes.

7.4.3 Revenue Decoupling Example: Idaho Power Company

Idaho Public Utilities Commission first approved a three-year revenue decoupling pilot program for the vertically integrated Idaho Power Company ("IPC") in 2007. This pilot program was extended for two more years in 2010. In April of 2012, Idaho Public Utilities Commission made the IPC pilot program permanent. IPC implements revenue decoupling through their Fixed Cost Adjustment mechanisms ("FCA") that compares the authorized fixed-cost revenue requirement with weather normalized sales and reconciles the difference annually for residential and small general service customers. FCA was established to separate billed energy sales from revenue in order to remove the financial disincentive from investing in Demand Side Management and energy efficiency activities.

For each class, the number of customers is multiplied by the fixed cost per customer rate (FCC), which is established as part of determining the Company's authorized revenue requirement in its most recent general rate case. The product of this calculation establishes the "authorized fixed cost recovery" amount. This authorized fixed cost recovery amount is then compared to the amount of fixed costs actually recovered by IPC. To determine the "actual fixed costs recovered" amount, the Company multiplies the actual billed sales for each class by the fixed cost per energy rate (FCE), as established in the Company's most recent applicable general rate case. The difference between these two numbers (the "authorized fixed cost recovery" amount minus the "actual fixed costs recovered" amount) is the fixed cost adjustment for each class.[133] The calculation is described by the following formula:[134]

$$FCA = (CUST * FCC) - (NORM * FCE) \tag{7.1}$$

Where:

CUST = actual number of customers
FCC = fixed-cost per-customer rate
NORM = weather-normalized sales for each class
FCE = cost-per-kWh rate

These adjustments are made annually through a rate adjustment filing that is reviewed and approved by the Idaho Public Utilities Commission.

[133] Idaho Public Utilities Commission. *Case No. IPC-E-24-10. Application.* March 15, 2024.
[134] Idaho Public Utilities Commission. *Case No. IPC-E-24-10. Direct Testimony of Grant T. Anderson.* March 15, 2024.

8 STAKEHOLDER ENGAGEMENT

8.1 Description of Stakeholder Engagement Process

As a part of an investigation into the applicability of PBR in the state of Indiana and in accordance with Indiana Code § 8-1-2.5-6.5 (d), CA Energy Consulting, with assistance from the IURC, collected input from electric utility stakeholders regarding current regulatory practices in the state, as well as preferences for possible changes. Engagement with utilities and customer groups in Indiana involved two surveys and a workshop to solicit feedback on topics such as MYRPs and PIMs. Comments from representatives of utilities and customer groups in the state provided insight into the feasibility of and interest in implementing new PBR tools in the state of Indiana. An additional survey was sent to regulators in the United States and Canada with experience in PBR, requesting insights on their lessons learned.

Each of the four parts of the stakeholder engagement process are summarized below.

<u>Part 1: Initial Survey (9/9/2024 – 9/27/2024)</u>

The stakeholder engagement process began with an initial survey to assess stakeholder familiarity with the key PBR concepts under consideration in this project: MYRPs and PIMs. The objective was to identify knowledge gaps among the stakeholders and to gauge initial support or opposition to these regulatory mechanisms.

<u>Part 2: Initial Stakeholder Workshop (10/17/2024)</u>

Informed by responses from the initial survey, CA Energy Consulting held a stakeholder workshop to provide foundational information on MYRPs and PIMs to align participant understanding. The workshop included time for discussion and dialogue.

<u>Part 3: Follow-up Survey (10/24/2024 – 11/22/2024)</u>

Following the October workshop, stakeholders received a second survey with questions informed by stakeholder discussions and feedback from the initial survey. The follow-up survey was divided into Utility and non-Utility versions and asked more specific questions about MYRPs, PIMs, and Indiana's current regulatory framework, aiming to capture stakeholder perspectives in more detail.

<u>Part 4: Survey to Regulators with PBR Experience (2/1/2025 – 2/28/2025)</u>

A survey was sent out to regulators from the United States and Canada to identify key insights from their experiences in implementing and then regulating PBR mechanisms such as PIMs and MYRPs. In total, eight different regulators were contacted, four from each country.

8.2 Stakeholder Feedback

8.2.1 Stakeholder Engagement Participation

Table 8.1 below depicts participation from the 18 Indiana stakeholders that were invited to provide feedback on PBR, 17 of whom were invited to respond to the initial survey. Over 50% of stakeholders responded to the surveys and attended the workshop. All but one stakeholder who responded to the initial survey responded to the follow-up survey.

Table 8.1: Summary of Engagement by Indiana Stakeholders

Stakeholders	Initial: Survey	Initial: Workshop	Follow-up: Survey
AARP Indiana	X	X	X
Advanced Energy United	X	X	X
AES Indiana	X	X	X
Black Sun Light Sustainability		X	
CenterPoint Energy Indiana	X	X	X
Citizens Action Coalition of Indiana	X	X	X
Duke Energy Indiana	X	X	X
Earthjustice			
Energy Matters Community Coalition			
Hoosier Environmental Council			
Indiana Energy Association		X	
Indiana Industrial Energy Consumers	X	X	X
Indiana Michigan Power Company	X	X	X
Indiana Office of Utility Consumer Counselor	X	X	X
Midwest Energy Efficiency Alliance			
NAACP Indiana			
Northern Indiana Public Service Company	X		X
Reliable Energy Indiana	X	X	

In addition to the 18 Indiana stakeholders, outreach was conducted with 8 regulatory commissions that have experience with PBR. Due to requests for confidentiality, the specific commissions are not identified. However, CA Energy Consulting received responses from 4 of these commissions, with 3 completing the survey detailed in Appendix C.2.3.

8.2.2 Initial Survey Methodology and Findings

On September 9th, 2024, an initial survey comprised of three questions was emailed to 17 stakeholder organizations with a notification that a response was requested by September 27th, 2024.[135] Table 8.2 summarizes the responses to Questions (1) (MYRPs) and (2) (PIMs), providing a baseline understanding on stakeholders' views of MYRPs and PIMs. The table simplifies each party's position in order to present survey feedback in a digestible format, with the drawback that it does not capture the nuances of each party's response. For instance, while the IOUs support the idea of MYRPs, their support is contingent upon these regulatory frameworks being optional, with allowance for each utility to propose company-specific PBR plans. Complete responses from each party can be found on the IURC's website.[136]

Table 8.2: Advisability of MYRPs and PIMs in Indiana

Stakeholders	MYRPs	PIMs
AARP Indiana	Against	Open to PIMs
Advanced Energy United	Open to MYRPs	Open to PIMs
Citizens Action Coalition of Indiana	Needs More Information	Needs More Information
Indiana Industrial Energy Consumers	Against	Against
Indiana Office of Utility Consumer Counselor	Against	Against
Investor-Owned Utilities	Open to MYRPs	Against
Reliable Energy Indiana	Open to MYRPs	Open to PIMs

Stakeholder feedback on the initial survey revealed a range of perspectives on MYRPs and PIMs. The survey included three questions: the first asked about the advisability of MYRPs in Indiana, the second focused on PIMs, and the third sought to identify additional information stakeholders need on these questions. Appendix D provides a copy of the survey questions.

Supporters of MYRPs highlighted possible benefits such as reduced regulatory lag, improved revenue and bill predictability, and lower administrative costs. Reliable Energy Indiana (REI) suggested that MYRPs, when paired with PIMs, could help address capacity, reliability, and resilience challenges. However, supporters raised concerns about reduced oversight of utility spending and whether a mandatory approach would be suitable given the diverse circumstances of the utilities. Opponents questioned whether MYRPs would, in fact, reduce rates for customers, and expressed skepticism about utilities' revenue forecasts, warning of potential risk shifting to consumers. Indiana Industrial Energy Consumers (INDIEC) argued that Indiana's existing framework already allows utilities to propose MYRPs, citing the recent CenterPoint Energy Indiana rate case.[137]

Stakeholders open to PIMs saw potential to align utility incentives with outcomes like improved customer service, grid reliability, and demand reduction. However, they stressed the need for clarity on implementation, with AARP recommending pilot programs before full adoption. Critics warned of unintended consequences and argued that utilities should not be rewarded for meeting basic service expectations. INDIEC opposed PIMs on these grounds, while investor-own utilities (IOUs) suggested participation should be voluntary if PIMs are introduced.

[135] Black Sun Sustainability was added later as a stakeholder on October 10th, 2024. They were provided with a copy of the initial survey questions, but no response was received by CA.
[136] https://www.in.gov/iurc/performance-based-ratemaking-study/
[137] IURC Cause No. 45590.

Additional feedback included a recommendation from Advanced Energy United (United) for the IURC to consult experience from other jurisdictions. The IOUs also a provided a list of key MYRP and PIM design elements for consideration.

8.2.3 Initial Stakeholder Workshop Findings

The initial stakeholder workshop was held on October 17th, 2024, and consisted of a virtual morning session conducted via Microsoft Teams.[138] The workshop was structured into five sections: 1) The Purpose of this Workshop and Project Background, 2) Defining Performance-Based Regulation, 3) Key Concepts of PBR, 4) Discussion of MYRPs, and 5) Discussion of PIMs. At the conclusion of the workshop, all stakeholders received an email containing a copy of the presentation, which also included an appendix with relevant case studies for further review.

The workshop served three objectives: first, to communicate the goal of the project – conducting a study to assess the applicability of various PBR frameworks for the state of Indiana; second, to establish a common knowledge base for all stakeholders before the follow-up survey was distributed; and third, to collect initial feedback from stakeholders on key issues specific to Indiana. Some stakeholder feedback informed the design of the follow-up survey, particularly in framing the question about whether stakeholders prefer incremental adjustments to the current regulatory framework or more comprehensive changes necessary to implement MYRPs and PIMs.

8.2.4 Follow-up Survey Methodology and Findings

Following the stakeholder workshop, a second survey was released on October 24, 2024. Responses were received from 10 of the 18 stakeholders (56%). Unlike the initial survey, utilities received a utility-specific set of questions, and a separate set of questions were provided to non-utility stakeholders. Many of the questions overlapped between the utility and non-utility versions of the survey, but segmentation by group allowed more targeted questions, such as inquiring with utilities about the feasibility of providing forecasts.

This section is organized into four categories of questions from the survey: 1) Stakeholder Workshop, 2) Current Regulatory Framework, 3) MYRPs and PIMs, and 4) Additional Information. See appendix D for the complete wording of each question.

8.2.4.1 Stakeholder Workshop Questions

Stakeholders were asked to evaluate the usefulness of the October 17th workshop in order to gather feedback on its value and to identify areas for improvement.

All respondents found the workshop valuable and felt they had sufficient opportunities to provide comments and ask questions. Stakeholders particularly appreciated the overview of alternative regulation and the timeline for evaluating PBR in Indiana. Suggestions for improvement included a comparison of Indiana's current regulatory structure with typical MYRPs and PIMs to highlight key differences. Citizens Action Coalition (CAC) recommended offering an in-person option to enhance engagement. One stakeholder suggested that CA Energy Consulting should provide a

[138] See Table 8.1 for which stakeholders attended the workshop.

deeper discussion of PBR guardrails, lessons learned from other states, and details on policy implementation.

8.2.4.2 Current Regulatory Framework Questions

Stakeholder feedback provided insights into regulatory goals, the effectiveness of Indiana's current rate-regulation framework, rate trends, affordability, cost efficiency, and capital investment cycles.

On regulatory goals, several stakeholders referenced Indiana's Five Pillars as a guiding framework, with IOUs highlighting additional considerations such as safety, utility financial integrity, and the importance of regulatory flexibility. INDIEC emphasized that the primary goal of regulation is to serve as a proxy for competition, while United called for a shift in regulatory focus towards creating a more reliable, affordable, resilient, innovative, stable, and environmentally sustainable grid.

When asked to assess the effectiveness of Indiana's current rate-regulation framework, responses were mixed. The IOUs generally rated the framework positively, marking most areas, such as reliability, resilience, and stability, as successful, though affordability and regulatory efficiency were rated as "Adequate". In contrast, other stakeholders, such as United and the Citizens Action Coalition of Indiana (CAC), were more critical, offering negative ratings across most areas. AARP specifically pointed out that affordability and utility cost control were major issues within the current framework and anticipated that these challenges would continue in the future. INDIEC, however, noted that the commission is adept at finding a balance and that the existing regulatory flexibility helps to adapt to the energy transition. The Indiana Office of Utility Consumer Counselor (OUCC) argued that alternative regulation would not benefit Indiana ratepayers and maintained that the current regulatory framework is adequate for the future. Table 8.3 summarizes the responses of stakeholders that provided itemized responses.

Table 8.3: Effectiveness of Indiana's Current Regulatory Framework

Stakeholders	AARP Indiana	Advanced Energy United	CAC	IOUs
How well does the current rate-regulation framework in Indiana facilitate success in the following areas? (Very well/Adequately/Neutral/Poorly/Very Poorly)				
Reliability	Neutral	Poorly	Neutral	Very Well
Resilience	Adequately		Neutral	Very Well
Stability	Neutral		Neutral	Very Well
Affordability	Poorly	Poorly	Very Poorly	Adequately
Environmental Sustainability	Neutral	Very Poorly	Very Poorly	Very Well
Utility cost control	Poorly	Poorly	Very Poorly	Very Well
Regulatory Efficiency	Neutral	Poorly	Adequately	Adequately
Customer Service / Connection Time	Neutral		Poorly	Very Well
Financial Health of the Utility	Very Well		Very Well	Very Well
Adaptability to the Energy Transition	Neutral	Poorly	Very Poorly	Very Well
Will the current rate-regulation framework in Indiana remain appropriate for optimizing utility services in the following areas, given the transition from coal power generation, and given the energy transition (e.g., adoption of distributed energy resources; electrification)?				
Reliability	Yes	No		Yes
Resilience	Yes	No		Yes
Stability	Yes	No		Yes
Affordability	No	No	No	Yes
Environmental Sustainability	Yes	No	No	Yes
Utility cost control	No	No	No	Yes
Regulatory Efficiency	Yes			Yes
Customer Service / Connection Time	No			Yes
Financial Health of the Utility	Yes			Yes
Adaptability to the Energy Transition	Yes	No	No	Yes

Regarding rate increases, stakeholders largely agreed that rates have risen faster than historical averages over the past decade. Many attributed this increase to capital investments, although factors such as the uneconomic operation of coal generation, general price inflation, and regulatory practices were also mentioned. The IOUs specifically cited inflation, environmental compliance requirements, capital investments, fuel cost changes, and increased electricity demand as the primary drivers of these rate hikes.

When asked about the capital investment cycle, all utilities acknowledged the existence of a cyclical pattern in capital investments, noting that they are currently in a phase that requires substantial investment over the next few years.

8.2.4.3 Feedback on MYRPs & PIMs

The survey also explored various aspects of regulatory approaches for utilities, focusing on the frequency of rate applications, the potential for MYRPs and PIMs, and the feasibility of operating under different performance-based regulation models.

Table 8.4 provides the frequency of fillings over the last 20 years across all five IOUs in Indiana. The IOUs indicated that they expect the frequency of these rate fillings to increase in the coming years.

Table 8.4: Rate Cases Since 2000

AES Indiana	CenterPoint Energy	Duke Energy Indiana	Indiana Michigan Power Company	Northern Indian Public Service Company
2014	2006	2002	2007	2008
2017	2009	2019	2011	2010
2023	2023	2024	2017	2015
			2019	2018
			2021	2022
			2023	2024

In response to whether a regulatory regime allowing optional MYRPs (vs. mandating them for IOUs) is supported, feedback was mixed. A key consideration for the feasibility of MYRPs is whether utilities can conduct detailed three-year revenue requirement forecasts at the FERC account level. Of the five utilities surveyed, three (I&M, CenterPoint, and AES Indiana) stated that they have this capability, while Duke Energy Indiana and NIPSCO stated they need more time or assumptions to perform these forecasts.

The survey also asked utilities to evaluate the feasibility of price and revenue caps over five years without filling rate applications. The IOUs expressed concerns about the Pure Price Cap and Pure Revenue Cap models, citing challenges in capital recovery and financial integrity. They noted the need for new generation, evolving generation portfolios, and increased transmission and distribution investments, make these models difficult to maintain. In contrast, the Hybrid Price Cap and Hybrid Revenue Cap options were viewed as more workable, with the Hybrid Revenue Cap preferred between the two. The utilities also suggested CA Energy Consulting examine the feasibility of formula rates.[139]

Two non-utility stakeholders, INDIEC and United, expressed conditional support for price or revenue caps. INDIEC's support was contingent on reviewing specific details, while United opposed price caps but was open to revenue caps, particularly if paired with revenue decoupling. Other stakeholders voiced concerns about affordability, lack of specific Indiana plans, and reduced regulatory oversight.

On the potential burden of validating multi-year revenue forecasts, most non-utility stakeholders felt it would be more complex than assessing a single future test year due to the need for greater

[139] It is important to note that formula rates are not generally considered to be PBR. Instead, formula rates offer utilities with a streamlined annual cost-of-service revenue update without the need for regular rate cases.

scrutiny of assumptions, methodologies, and projections. United note this burden might lessen over time as stakeholders become more familiar with the process.

Stakeholders generally agreed that utilities could benefit financially from price or revenue caps, though the IOUs found the definition of "financial benefit" unclear. When asked about customer benefits resulting from indexed cap PBR, CAC and OUCC expressed skepticism, citing insufficient evidence of customer gains. United also questioned the justification of such a framework without clear customer benefits. However, INDIEC and the IOUs identified bill predictability as a potential benefit.

Regarding PIMs, the OUCC expressed cautious openness, suggesting that PIMs should reward utilities for service above standard expectations. Except for the OUCC adjusting its view on PIMs, the responses aligned with responses from the initial survey.

Perspectives varied on how to define the success of MYRPs and PIMs. The OUCC, United, and CAC focused on lower residential bills, with United and CAC also emphasizing environmental sustainability, reliability, resilience, and transparency. INDIEC defined success as utilities maintaining effective and efficient service, while IOUs highlighted financial integrity, timely investments, rate predictability, performance incentives, and state policies. This feedback suggests that success could be evaluated within the context of the Five Pillars.

Finally, when asked about incremental updates to Indiana's regulatory structure instead of implementing MYRPs, there was broad consensus favoring refinement over a significant overhaul. CAC suggested several possible incremental updates such as residential rate reform, curtaining or removing trackers and riders, and discontinuing the use of future test years.

8.2.4.4 Additional Information

Stakeholders provided additional feedback on the exploration of PBR for Indiana utilities, as well as the potential for a second workshop.

Regarding PBR, stakeholders suggested that reviewing case studies from other jurisdictions could help better understand the application of PBR in different contexts. United recommended inviting impartial experts from regulatory commissions that have implemented MYRPs and PIMs to future workshops.

All three stakeholders who responded expressed interest in a second workshop. United proposed focusing on policy goals and how they would be developed and reviewed. The CAC expressed interest in case studies and emphasized the preference for an in-person format. The IOUs recommended a workshop that addresses how PBR can be adapted to accommodate utilities' capital investment needs, including more detailed discussions on off-ramps and re-openers. They also suggested a third workshop focused on reviewing the report from CA Energy Consulting to the IURC.

8.3 Survey of Regulators in Other Jurisdictions

To gain an understanding of the experience of PBR frameworks that have been enacted elsewhere, we sent surveys to eight regulatory authorities across North America. Of these, seven current regulate utilities operating under some form of PBR. One regulated under a PBR framework but has since returned to COSR.

Among the eight respondents to the survey, three regulatory agencies provided detailed and substantive feedback. One agency requested anonymity; accordingly, their insights are included without identifying information to preserve confidentiality. These three regulators represent distinct ends of the regulatory spectrum – two oversee transmission and distribution-only electric utilities, while the other regulates vertically integrated electric utilities. Their respective experiences with PBR offer contrasting perspectives that underscore the diverse considerations and challenges associated with adopting and maintaining such frameworks.

The regulator of integrated utilities reported a generally positive experience with PBR mechanisms. Their framework includes a MYRP with embedded PIMs, developed through an intensive, regulator-initiated stakeholder process. Since implementation, stakeholder feedback has been broadly supportive, and the regulator anticipates continued use of PBR. However, the framework has evolved over time: some PIMs have been retired due to performance outcomes, while others have been introduced to address emerging issues such as grid modernization and the integration of DERs. While the frequency of general rate cases has declined, the regulator noted mixed feedback regarding the administrative burden of PBR – citing reduced rate case workload but increased demands associated with managing the ongoing workgroup process.

In contrast, one of the regulators overseeing transmission and distribution-only utilities adopted PBR mechanisms in response to a statutory requirement. Their approach also centered on MYRPs and PIMs. This regulator commissioned an independent study to evaluate the advantages and drawbacks of various PBR designs. Ultimately, they found that the implemented mechanisms fell short of expectations – citing limited regulatory relief, challenges in developing an effective indexation formula, and a lack of evidence that PBR had delivered cost savings for either customers or the regulator.

For the other transmission and distribution-only regulator, implementation of PBR – like that of its counterpart – was driven by the legislature. Their PBR approach includes a range of elements including revenue decoupling, revenue and price caps, and ESMs. Additional PBR options are currently being explored, with utilities able to select from a menu of rate plans based on their specific investment needs. To guide the development of its PBR framework, the regulator has engaged in consultations with stakeholders and subject-matter experts to identify key design features. Overall, the regulator has found that PBR has helped reduce regulatory burden through more mechanistic rate adjustments, even if the burden associated with individual rate cases has not necessarily decreased.

8.4 Summary of Stakeholder Engagement

Stakeholder feedback is instrumental in assessing Indiana’s current regulatory landscape and the potential for adopting MYRPs and PIMs.

Overall, there is some openness among stakeholders for pursuing MYRPs, with IOUs expressing tentative interest in exploring an optional approach. One area of relative agreement across groups interested in MYRPs is a preference for revenue caps rather than price caps. The IOUs stated that a revenue cap approach would need to be contingent on the inclusion of specific trackers. Other stakeholders expressed significant concerns about the feasibility and practicality of implementing both indexed cap and forecasted MYRPs in Indiana, citing concerns about impacts on affordability, lack of regulatory oversight, lack of details on a specific Indiana plan, and increased time to validate forecasts.

Stakeholders voiced broader interest in exploring PIMs, although perspectives vary regarding their structure. Key questions remain about whether PIMs should be optional or mandatory, focus solely on penalties, or include rewards for exceeding performance metrics.

The overwhelming preference for incremental changes highlights the stakeholders' preference for a measured approach that builds on the current system rather than introducing sweeping reforms.

9 SCENARIO ANALYSIS

Perhaps the most difficult step in evaluating a new set of regulatory tools is predicting the outcome of transitions from the status quo framework. The development of hypothetical scenarios can assist by providing stakeholders with a window into potential outcomes grounded in real data. Scenario analysis can reveal whether the proposed metrics and incentives effectively align with desired policy goals, identify potential risks or inequities, and provide a basis for refining the regulatory design in the form of further stakeholder engagement.

In this section, we provide hypothetical scenarios for indexed cap PBR frameworks, as well as a scenario analysis of PIMs. The scenarios draw upon historical data from Indiana's five IOUs, as well as industry-wide cost and output data obtained from the FERC Form 1. Existing data is not sufficiently rich to predict how IOUs will respond to the incentives, which means that behavioral changes from PIMs or indexed caps must be assumed. Despite such limitations, the scenarios demonstrate how PBR tools discussed in this report would operate using data specific to Indiana's utilities.

Because of the breadth of tools that fall under the umbrella of PBR, we have conducted scenario analysis only on certain mechanisms. In the category of MYRPs, we present analysis regarding indexed cap plans. Indexed caps employ industry data to set price or revenue growth over time, and this data is readily accessible, where projections of individual utility costs (required for a forecasted MYRP analysis) are proprietary and not available for the purposes of this study. Regarding PIMs, we have analyzed reliability PIMs, as reliability data from Indiana's utilities are publicly available.

The objective of this section is to demonstrate how these tools work, not necessarily to predict the future if these tools are put in place.

9.1 Price Cap and Revenue Cap Scenarios

In this section, we present projections of the impact on rates in Indiana resulting from different indexed cap structures currently in effect in jurisdictions across North America. The goal of this scenario analysis is both to illustrate how such caps work in practice and to provide a forecast of how ratepayers would be affected. Consequently, these projections are produced using actual historical data on fully integrated utilities using methods that mirror those used in past PBR rate proceedings. For simplicity, we structure these caps initially as revenue caps, but, as shown in Appendix B, a corresponding price cap is derived by simply subtracting the utility's growth rate in output. We consider two cap scenarios.

As summarized in 10.1, we ultimately recommend a hybrid cap structure that applies the indexed cap to distribution rates only. For this reason, we remove generation and transmission costs and consider a revenue requirement intended only to cover the distribution portion of the company's service.

In the first scenario, the company's total distribution revenue growth is capped for each year during the PBR term.[140] This cap structure incentivizes cost containment for both distribution O&M expense (OPEX) and distribution capital expense (CAPEX) and thus places the greatest downward pressure on rates in the long run. However, there may be concern about the risk of underinvestment by utilities, particularly if the state of Indiana is in a period of transition that requires significant capital investment.

The second scenario reduces this risk of underinvestment by applying PBR incentives to OPEX only. The company's total distribution revenue is bifurcated into revenues associated with OPEX and CAPEX. The growth in revenue designated to cover OPEX is capped. In contrast, CAPEX is recovered via traditional cost of service regulation. This mechanism ensures that the utility receives revenues that enable it to recover the costs associated with capital investments while still placing efficiency pressure on OPEX.

It may be useful to view Scenarios 1 and 2 as two extremes, within which one could imagine carving out only a subset of capital expenses to be funded via cost of service, and leaving the rest under the cap. With regard to the impact on rates, the results suggest that these other scenarios may be reasonably approximated by Scenarios 1 and 2, as the difference in our projections of rates under these two scenarios is small.

Below, we walk through the structure of each cap scenario, discuss the advantages and disadvantages of each, and quantify the impact on rates under a hypothetical PBR term lasting from 2025-2029. It is important to note that we are unable to provide a projection of how utility costs will change, as this is unrelated to the cap structure and will depend on how the utilities react to PBR incentives.

9.1.1 Scenario 1 Overview

In Scenario 1, the growth rate in the utility's total revenue is capped by *I-X+G.*[141] An illustrative example is contained in Table 9.1 for a hypothetical PBR term lasting from 2025-2029. Rates are set in 2024 via a cost of service proceeding and then escalated each year from 2025-2029 by *I-X*. In this example, inflation growth *I* is equal to 2%, *X* is equal to -2%, and *G* is 1% in each year, leading to a revenue cap of 5%[142]. This is shown in the "Total Revenue" column in Table 9.1. This 5% growth reflects the revenue the utility needs if it continues to operate with approximately average productivity growth. Because the utility is able to retain a share of the profits it earns from reducing total cost, it is incentivized to find cost efficiencies, leading to total cost growth of only 3% per year in this example. Because the total revenue growth trajectory of 5% reflects productivity trends in the peer group (which, by design of the peer group selection, on average closely approximates the historical performance of the utility in question), this 3%

[140] In this analysis, the total distribution revenue cap is set to cover distribution O&M expense and distribution capital expense in the rebasing year and is escalated by *I-X+G* each year during the plan. O&M expense is comprised of total distribution operations and maintenance expense plus customer account expenses, sales expenses, and a share of administrative and general (A&G) expenses; the share of A&G expenses is determined by the ratio of distribution plant to total plant. Total capital expense is equal to depreciation and amortization expense for distribution plant plus distribution plant rate base multiplied by the weighted average cost of capital.

[141] See Appendix B for a derivation of the price and revenue cap formulas.

[142] In practice, while X is generally held fixed, *I* and *G* are allowed to vary throughout the term. They are assumed to be constant in this example for simplicity.

growth is possible only because the utility becomes more productive. When the utility rebases after the PBR term concludes in 2029, its efficiency growth is then passed on to customers in the form of lower rates.

Table 9.1: Scenario 1 Example (in millions)

Year	*I*	*X*	*G*	*I-X+G*	Total Revenue	Total Cost
2024	-	-	-	-	1,000	1,000
2025	2%	-2%	1%	5%	1,050	1,030
2026	2%	-2%	1%	5%	1,103	1,061
2027	2%	-2%	1%	5%	1,158	1,093
2028	2%	-2%	1%	5%	1,216	1,126
2029	2%	-2%	1%	5%	1,276	1,159

Because the utility is incentivized to minimize both OPEX and CAPEX, this cap structure places the greatest downward pressure on costs. This may be more desirable for a regulator who is concerned with providing the lowest possible rates in the long run, and is less concerned with the risk of underspending, especially if the cap is effectively paired with PIMs that penalize the company for such underspending.

9.1.2 Scenario 2 Overview

Scenario 2 combines elements of cost-of-service regulation with performance-based regulation in order to reduce the risk of underinvestment. This risk has been observed in the literature:

> "The under-investment problem under incentive regulation is likely to be most acute under plans that cap price at a level intended to cover both capital and operating costs, leaving to the utility decisions about expenditures on each. … This understanding has prompted regulators to modify incentive plans so as to treat operating and capital costs differently. The most common variant involves the use of straightforward incentive regulation for operating costs but more traditional regulation of the utility's investment. This reflects the … fact that incentive regulation seems well designed for conservation of operating costs, but less well suited to investment behavior and costs. This hybrid approach may in fact capture the comparative advantage of each mode of regulation (Kwoka, 2009, p. 15)."[143]

In this scenario, the company's total revenue is bifurcated into revenue associated with OPEX and revenue associated with CAPEX. The revenue designated to cover OPEX is set to grow at the rate *I-X+G* over the course of the PBR term. Note that because the index formula in this scenario is being applied only to revenues associated with OPEX, the index formula values need not be the same as the values in Scenario 1, and in general the X factors will differ significantly. In contrast, the revenue covering CAPEX is recovered via cost of service; for instance, the company may use

[143] Kwoka, John, "Investment Adequacy under Incentive Regulation," Northeastern University Working Paper, 2009.

a forecast of its capital spending over the PBR term to serve as the basis for rates, which are then adjusted to reconcile actual spending with forecasted spending.

If the utility is in a period of transition and must make significant capital investments, the advantage of this approach is that it encourages the company to invest, while still allowing the utility to profit from OPEX efficiencies that customers ultimately benefit from. An example is shown in Table 9.2. In this example, the utility's growth in revenues associated with OPEX reflects peer group productivity trends and implies a growth rate of 4% per year. If the utility were to follow these trends, it would arrive at OPEX of 608 million in 2029. However, because the utility is able to retain a portion of its OPEX savings, it is incentivized to reduce OPEX and instead arrives at an OPEX of 552 million. When rebasing occurs, O&M savings are passed on to customers in the form of lower rates during the next PBR term. On the other hand, CAPEX funding varies with actual CAPEX. The company overspends by 10 million in 2025 relative to the forecast, and is then granted an additional 10 million in 2026 in response following an annual prudence review.[144] It then spends the forecast in 2027, 2028 and 2029. Thus, it spends 10 million more than the forecast over the term and revenues adjust upward to compensate the utility. Because funding adjusts with actual spending, there is no incentive to find CAPEX efficiencies.

Table 9.2: Scenario 2 Example (in millions)

Year	*I-X+G*	Funded OPEX	Actual OPEX	CAPEX Forecast	CAPEX Funding	Actual CAPEX
2024	-	500	500	500	500	500
2025	4%	520	510	520	520	530
2026	4%	541	520	541	551	541
2027	4%	562	531	562	562	562
2028	4%	585	541	585	585	585
2029	4%	608	552	608	608	608

This example illustrates how the cap mitigates the risk of underspending on capital. If CAPEX were capped at the CAPEX forecast, say, the company would attempt to operate below the CAPEX Funding amounts in all years. If this 10 million in overspending relative to the forecast was essential, the company may have tried to minimize it to the detriment of customers.

By handling capital spending outside of the cap through a cost-of-service mechanism, investment is encouraged by giving utilities a predictable return on capital additions. Utilities are not incentivized to try to minimize spending on projects that may largely be outside of their control. Instead, the focus for cost efficiency discovery is placed on O&M expenses, over which the utility arguably has more control. By placing the cap on O&M, the utility is incentivized to find cost efficiencies that are readily available, rather than in the areas of capital spending initiatives the regulator has deemed important for ratepayers in the long run.

However, in addition to not placing the strongest downward pressure on rates, this cap structure has other disadvantages. First, combining a cap on revenues associated with OPEX with full cost recovery on capital costs may lead to inefficient input choices. Because the company is

[144] For simplicity, this calculation does not account for carrying costs.

compensated for any capital expenses and rewarded for reductions in O&M expenses, it may attempt to allocate more spending in a project to capital. Second, carving out capital expenses may lead to excessive capital investment, particularly if the company's allowed rate of return is higher than its cost of capital.

9.1.3 Data and Summary Statistics

The remainder of this section examines the impact on rates under Scenarios 1 and 2 using industry data and the accepted empirical methods employed in PBR proceedings. These data primarily come from the FERC Form 1; we collect data on OPEX, CAPEX, kWh, and total customers for fully integrated utilities from 2009 to 2023. We supplement this dataset with inflation data from the Federal Reserve Economic Data (FRED) database.

To calculate the X factor in each scenario, we employ the Kahn method. This method derives *X* using the observation that if, in our sample, utility revenue is equal to cost on average, and the growth rates of revenue and cost are equal on average, then the X factor can be recovered from the relationship inferred in Appendix B.2. Specifically, that relationship is average revenue growth = $I - X + G$, where I, X, and G are equal to the average values in the sample. Replacing average revenue growth with average cost growth,

$$X = I + G - \textit{average cost growth} \tag{9.1}$$

where I is average input inflation in the sample and G is average output growth. Output growth is defined to be an equal-weighted index of customer and kWh growth, and input inflation is an equal-weighted index of the Employment Cost Index for private industry workers and GDP-PI growth. In order to remove outliers, the Kahn method retains only those utilities that fall within the 25th- 75th percentile of unit cost growth in the sample, where unit cost is defined as total cost divided by total customers.

The results of the X factor study along with summary statistics for the sample (denoted by Industry) and for the Indiana utilities are shown in Table 9.3.

Table 9.3: Results of X Factor Study (Variables Averaged From 2009-2023)

	Industry	Indiana
X (Scenario 1)	-1.7%	-1.8%
X (Scenario 2)	-0.16%	-0.12%
I (Input Price Growth)	2.6%	2.6%
G (Output Growth)	0.57%	-0.37%
Total Cost Growth	4.8%	4.0%
CAPEX Growth	5.7%	5.4%
OPEX Growth	3.2%	2.3%

The results suggest that the productivity growth rates for Indiana utilities are close to the sample average. While the average utility in Indiana experienced slower distribution cost growth at 4% relative to the industry's 4.8% growth, it experienced slightly negative output growth, leading to very similar X factors for Scenario 1. For Scenario 2, the X factor should reflect partial factor productivity rather than total factor productivity, since only inputs specific to OPEX are considered. We calculate the corresponding X factor by replacing total cost growth with OPEX growth.

The reason for comparing Indiana utilities to the industry is that an ideal sample will have historical productivity trends similar to the regulated utility. Because the utility will be regulated under the index cap formula that contains the industry X factor, it is important that these are similar. For instance, if Indiana utilities had X factors that were much more negative, an indexed cap would imply rate growth that is much slower during a PBR term than the utilities are accustomed to, which could risk jeopardizing the financial integrity of the companies. Incorporating the Indiana utilities' X factors into the cap formula could serve as a substitute in this case, but then the utilities would be punished in subsequent PBR terms for improving their productivity during the term in the form of a more positive X factor in later PBR terms, reducing their incentives to find cost efficiencies. In other words, it is important that the industry peer group serves as the benchmark and that this peer group has similar productivity trends to the regulated utility, which is supported by Table 9.3.

9.1.4 Indexed Cap Scenario Analysis

This subsection presents the projected impact on rates under each of our two scenarios. We begin by presenting the main result in Table 9.4. Then, we unpack the underlying cap structure in each scenario to examine the determinants of the projections.

Table 9.4: Projected Price Growth Under Each Scenario

	Scenario 1	Scenario 2
2025	4.3%	4.7%
2026	4.3%	4.8%
2027	4.3%	4.8%
2028	4.3%	4.8%
2029	4.3%	4.9%

For Scenario 1, price growth is simply equal to I-X, which, from Table 9.3, implies that price growth is projected to be 2.6% - (-1.7%) = 4.3%.[145] This is based on a projection for inflation that is equal to the historical average.

For Scenario 2, projected price growth is more complicated to estimate. This is because revenue growth is not based solely on the cap, but includes the capital investment forecast as well. To derive this, note, based on the derivations in Appendix B, that price growth can be derived from revenue growth by simply subtracting output growth. Therefore, we can estimate price growth during the PBR plan under Scenario 2 by first estimating revenue growth. Revenue growth can be expressed as

$$Revenue\ growth = OPEX\ revenue\ growth * OPEX\ share + CAPEX\ revenue\ growth * CAPEX\ share \quad (9.2)$$

[145] See Appendix B for the derivation of the I-X formula.

OPEX revenue growth is simply equal to $I\text{-}X\text{+}G$, where the appropriate X factor is -0.16% from Table 9.3. However, one still needs a CAPEX forecast as well as the projected share of OPEX and CAPEX in total cost. In order to obtain these projections, we forecast OPEX and CAPEX for the Indiana utilities from 2025-2029 using their average historical growth rates. Once these forecasts are obtained, the OPEX share is set equal to OPEX / (OPEX + CAPEX), the CAPEX share is set equal to 1 – OPEX share, and CAPEX revenue growth is set equal to the forecasted CAPEX growth. Once this revenue growth has been estimated, price growth is obtained from Appendix B.2 as

$$Price\ growth = Revenue\ growth - Output\ growth \tag{9.3}$$

This requires a projection of output growth as well, which is also based on its historical growth rate. Once price growth has been estimated for each Indiana utility in each year, an average is calculated for that year, as shown in column 2 of Table 9.4.

Ultimately, the price growth estimates under Scenario 2 are slightly higher. This reflects the fact that cost growth is expected to be higher in the future than in the past as capital costs, which have grown faster than O&M costs, comprise a larger share of total costs. Whereas Scenario 1 incorporates the slower historical cost growth rate into the $I\text{-}X$ formula, Scenario 2 accounts for the faster cost growth rate in the future, yielding faster rate growth. This highlights the benefits and drawbacks of the indexed cap approach. Because the X factor is estimated using historical data, utilities will be undercompensated if they are expected to experience cost growth in the future that outpaces cost growth in the past. If Scenario 1 is chosen, capital supplements like K-bar are generally recommended in order to account for this discrepancy. This issue would not be present in Scenario 2, but this scenario does not incentivize capital cost containment and can lead to unintended consequences as described in 9.1.2.

Thus far, we have discussed only projections of rates. In contrast to the rate projections, the utilities' cost trajectories under each scenario are unlikely to be as similar. Predicting these cost trajectories with precision is not possible, as they depend on how utilities choose to respond to their incentives; economic theory can only serve as a guide for the general patterns that should be expected. Under Scenario 1, the utility is incentivized to control costs for both OPEX and CAPEX, whereas the utility has no such incentive for CAPEX under Scenario 2. As discussed above, in Scenario 2, the utility may be incentivized to increase CAPEX more than necessary if such increases reduce OPEX, allowing it to increase profit. Thus, the Scenario 2 figures in Table 9.4 should likely be considered lower bounds on the rate increases that customers would ultimately pay. Almost certainly, CAPEX growth will be lower under Scenario 1, but it is not possible to say if OPEX growth will be lower under Scenario 1 or 2.

9.2 PIMS Scenarios

A PIM is an annual revenue adjustment mechanism that ties financial incentives to the achievement of pre-defined benchmarks or targets. PIMs address policy goals related to utility outputs. These outputs could include measures tracked through existing service quality indicators—for example SAIDI or SAIFI—or they could involve outputs tied to specific new objectives, such as greenhouse gas emissions mitigation efforts or DER connections. Notwithstanding debates about reasonableness or implementation details, the only constraint on applying a PIM to any output measure is that data exists to track utility achievement. We discuss considerations for designing PIMs in Section 6.

As discussed in Section 8, we engaged with stakeholders through a workshop and two surveys to better understand current policy priorities. Survey respondents communicated a preference for incremental change to the state's regulatory framework, as opposed to larger changes that might cause disruption. Given this preference, PIMs may be a reasonable set of tools for consideration in Indiana. Although stakeholder engagement did not result in consensus regarding policy goals, metrics to address those goals, or implementation details, feedback indicated a preference for robust reliability in electricity service. We therefore present hypothetical scenarios for possible reliability PIMs.

The state's IOUs currently report reliability measures in the form of SAIDI, SAIFI, and CAIDI. We draw upon 14 years of historical data (2010-2023) from the Indiana Utility Regulatory Commission's Electric Utility Reliability Report (2023) to illustrate the mechanics of two possible reliability PIMs. We address the fact that a PIM can be reward-only, penalty-only, or "symmetric" by first illustrating the results of a hypothetical penalty-only SAIDI PIM, and, second, using the same data to show the results of a symmetric SAIDI PIM.

While these scenarios aim to provide helpful context in the design of PIMs in Indiana, they are not intended to be precise recommendations for Indiana's next step into PBR. This is because, as mentioned elsewhere, PIMs should be implemented either (i) as part of a rate application process where the tools are assessed on a case-by-case basis in the context of the entire utility's plan; or (ii) through a focused stakeholder engagement process where utilities and stakeholders provide input into policy priorities, what metrics best measure the achievement of those priorities, and what financial incentives are appropriate. Further scenario analysis could be developed after settling on new or underemphasized policy objectives that Indiana's regulatory framework aims to address.

9.2.1 Scenario 1: Penalty-Only SAIDI PIM

For each scenario, we have created a prototypical utility, which we will call "the Indiana Utility." We have created the Indiana Utility using an amalgamation of reliability data from all five of Indiana's IOUs. For this scenario, we assume that the PIM was implemented in 2018. We calculated the customer weighted average SAIDI measure for years 2010 through 2017 (this corresponds to the threshold approach based on a utility's own past performance, described in Section 6.4). This provides us with a hypothetical scenario using real data, without singling out any particular IOU.

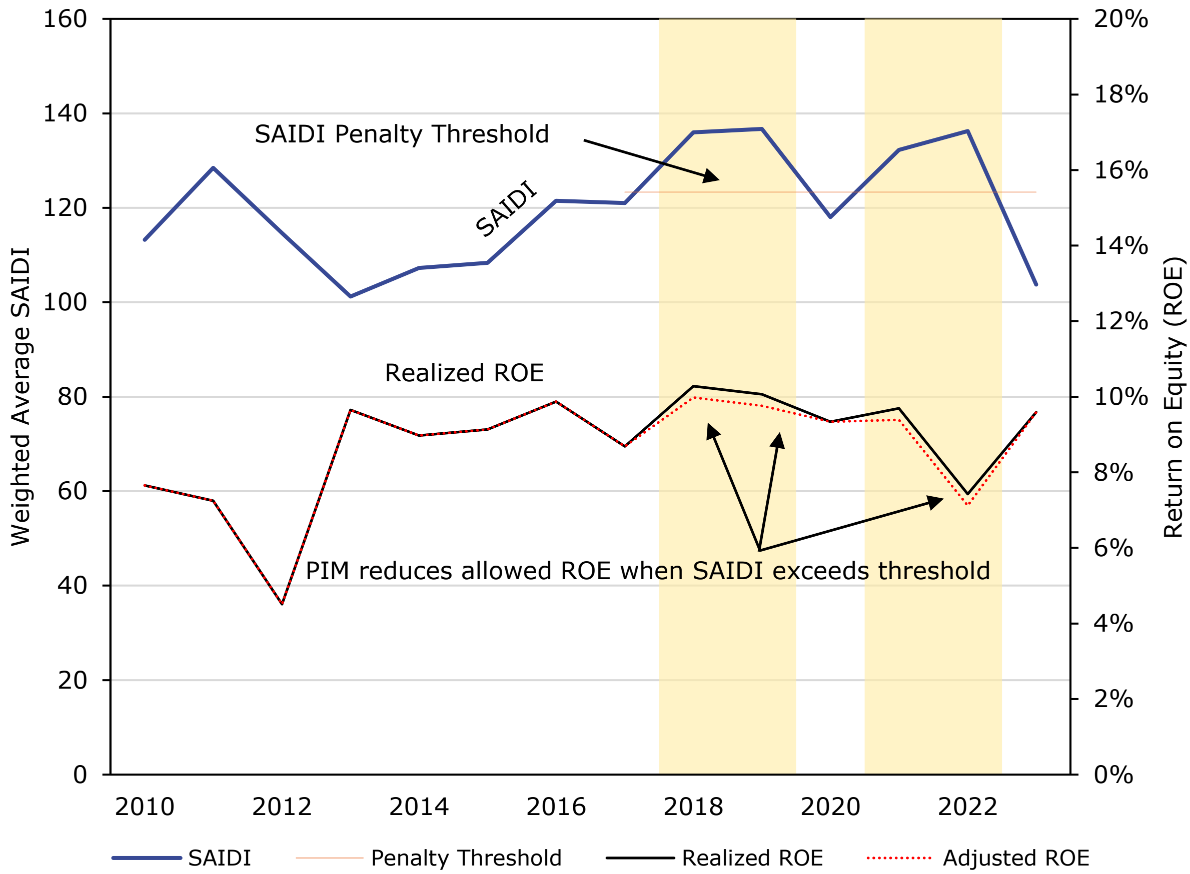
This first scenario presents a penalty-only reliability PIM imposed on the Indiana Utility. The PIM has a penalty threshold equal to one standard deviation above the mean SAIDI value from 2010 to 2017 (*threshold = mean SAIDI value + one standard deviation = 114.44+8.89 = 123.33*). If the utility's SAIDI value in a given year passes this threshold, a penalty is administered, equal to 0.30 percentage points of the utility's ROE. Table 9.5 summarizes the key parameters of the PIM.

Table 9.5: Parameters of Penalty-Only SAIDI PIM

Parameter	Definition	Value
Penalty Threshold	Mean SAIDI plus one Standard Deviation	123.33 minutes
Penalty Amount	Deduction from realized ROE for a given year	0.30%

The PIM works such that when the Indiana Utility's SAIDI level exceeds 123.33 minutes in a given year, the allowed ROE is reduced. Figure 9.1 depicts the actual results of this PIM. It shows that in years 2018, 2019, 2021, and 2022, this PIM would have administered a penalty, lowering realized ROE (black line) to an adjusted ROE (the red line).

Figure 9.1: Scenario 1, Penalty-Only SAIDI PIM



This hypothetical PIM would have returned $38.2 million to consumers since 2018.[146] While this penalty amount is prototypical in this example, a value of lost load (VOLL) study could be conducted to assess the appropriate penalty amount for a reliability PIM. VOLL reflects the value a customer would pay to avoid an outage, or should be compensated if an outage occurs. As

[146] The following table presents net income and penalty information for the years when the Scenario 1 penalty-only SAIDI threshold was surpassed.

Year	Net Income	Total Penalty Amount
2018	$286,085,895	$8,611,025
2019	$304,443,043	$9,064,507
2021	$323,316,490	$10,208,921
2022	$206,735,841	$10,347,391

noted in Section 6.5, PIM rewards and penalties should be set according to marginal costs and marginal benefit information.

An additional note is that this scenario uses actual SAIDI data from the Indiana IOUs. If this PIM were in fact implemented, the IOUs would likely change their behavior in an effort to reduce SAIDI and avoid the penalty.

9.2.2 Scenario 2: Symmetrical SAIDI PIM

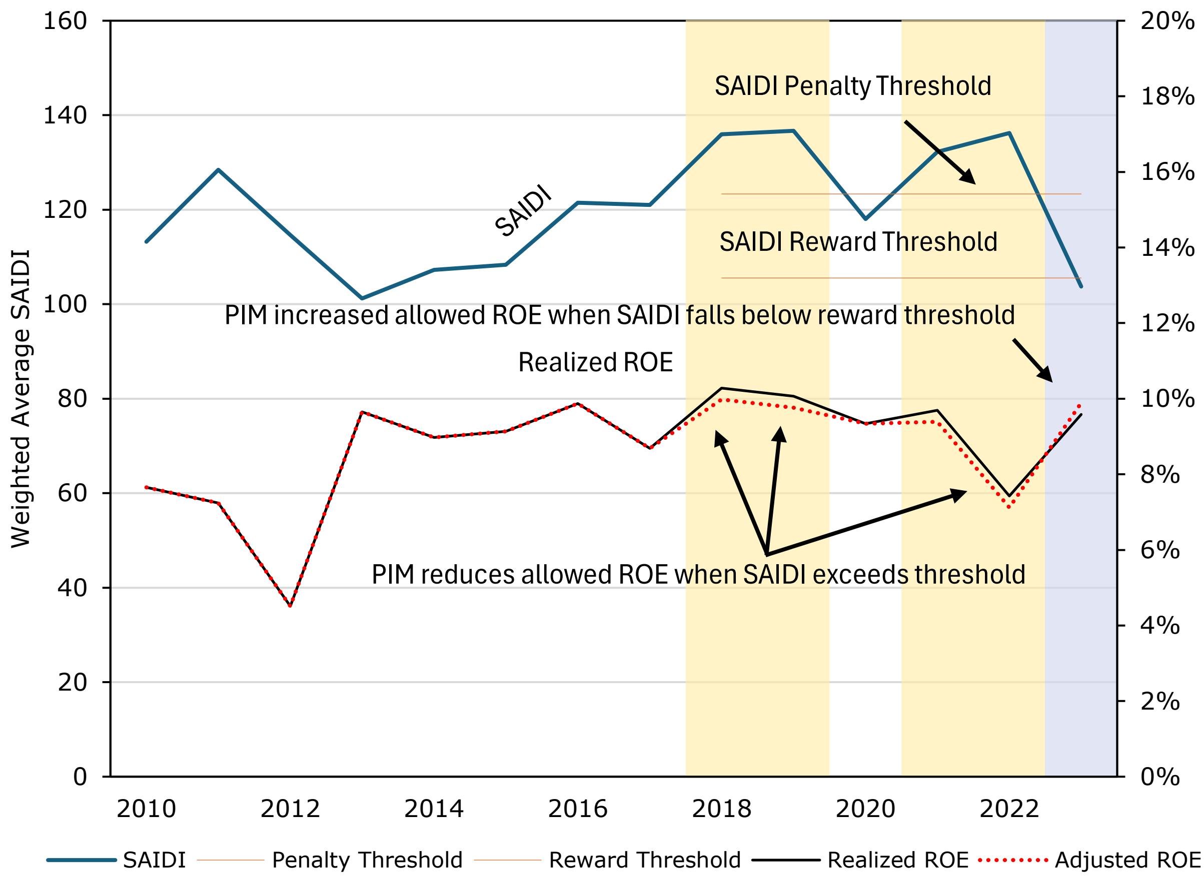
The second scenario alters the penalty-only reliability PIM from Scenario 1 to incorporate a reward. A PIM with both a reward and a penalty is considered "symmetrical." In this case, the PIM has the same penalty threshold as Scenario 1, equal to one standard deviation above the mean SAIDI value from 2010 to 2017. The reward threshold is calculated similarly, as the mean SAIDI value minus one standard deviation. Table 9.6 summarizes the key parameters of the PIM.

Table 9.6: Parameters of Symmetrical SAIDI PIM

Parameter	Definition	Value
Penalty Threshold	Mean SAIDI plus one Standard Deviation	123.33 minutes
Penalty Amount	Deduction from realized ROE for a given year	0.30%
Reward Threshold	Mean SAIDI minus one Standard Deviation	105.55 minutes
Reward Amount	Addition to realized ROE for a given year	0.30%

The PIM works such that when the Indiana Utility's SAIDI level exceeds 123.33 minutes in a given year, the allowed ROE is reduced. Figure 9.2, which depicts these results, appears similar to the Scenario 1 illustration. It shows that the PIM would have administered a penalty during the same years as in Scenario 1—as this Scenario draws upon the same data and has the same penalty threshold. However, the reward component has been added. Just as exceeding the penalty threshold lowers realized ROE to an adjusted ROE, a smaller outage time in the form of a lower SAIDI value results in an increased ROE when a reward is added. The Indiana Utility receives a reward in 2023.

Figure 9.2: Scenario 2, Symmetrical PIM



The Scenario 2 PIM would have returned $38.2 million to consumers since 2018 through the penalty, and the utility would have earned $11.6 million in rewards for a net of $26.6 million returned to customers in the form of penalties.[147] As discussed in Scenario 1, a value of lost load (VOLL) study could be conducted to assess the appropriate penalty and reward amount for a reliability PIM.

9.2.3 Summary of Findings from PIMs Scenarios

The first step in developing PIMs is to establish policy priorities. Then, PIMs can be evaluated as potential tools to address these priorities. In some cases, PIMs may not be best suited to

[147] The following table presents the penalties and rewards for the symmetrical PIM in years when the SAIDI thresholds were breeched.

Year	Net Income	Total Penalty Amount	Total Reward Amount
2018	$286,085,895	$8,611,025	
2019	$304,443,043	$9,064,507	
2021	$323,316,490	$10,208,921	
2022	$206,735,841	$10,347,391	
2023	$346,999,490		$11,621,997

facilitating a particular regulatory goal. For example, as tools concerned primarily with utility outputs (rather than inputs), PIMs do not generally address cost efficiency.[148] Implementation difficulties may further hinder the application of PIMs, for example if performance cannot be measured accurately, or if performance falls beyond the control of management.

The hypothetical scenarios above make several assumptions. First, both scenarios assume that reliability is a policy objective. Second, it is assumed that SAIDI measures adequately reflect reliability and can be controlled by the utility. Third, we have assumed that a historical average SAIDI value serves as an accurate baseline for future years, and that reward/penalty threshold values equal to one standard deviation above or below the mean are reflective of thresholds beyond which incentives should apply. Fourth, we assume the value of penalties and rewards. When designing a real-world PIM, practitioners should aim to replace these assumptions with the results from real-world analytics.

Both scenarios show that, if a standard deviation value based on historical data is used to set a PIM threshold for the future, the threshold is likely to be crossed from time to time (though this is not guaranteed). A consideration in the design of PIMs is whether to use the utility’s own past data as a baseline, or whether some comparison could be made with other utilities contemporaneously. Preferences for an approach will depend on the metric.

[148] However, a PIM that aims to reduce peak load or connect DERs could potentially improve affordability by reducing infrastructure investments required to increase peak capacity.

10 SUMMARY OF RECOMMENDATIONS AND CONCLUSIONS

PBR encompasses a suite of regulatory mechanisms that offer utilities enhanced incentives compared to traditional regulation. The incentive power of these mechanisms exists along a continuum, meaning the demarcation between PBR and conventional regulatory practices can be challenging to pinpoint. This report has described the principal tools generally classified as PBR that are currently in use in North America and has articulated best practices for the design of these incentive-based mechanisms, with the objective of making recommendations to the IURC for possible changes to Indiana's current regulatory framework.

The first step in making recommendations for regulatory change is to identify the policy objectives. In Indiana, the "Five Pillars" of reliability, affordability, resiliency, stability and environmental sustainability form the basis of the state's electric utility regulation. Stakeholders, both in discussion workshops and in responding to surveys, confirmed these priorities, with a somewhat heightened focus on the issue of affordability for customers.

Whether PBR can improve upon the realization of the Five Pillars depends on current industry conditions and regulatory practice in the state. Indiana's IOUs operate largely in the MISO footprint (Indiana Michigan Power Company also operates in PJM), meaning generators sell electricity on the wholesale market and MISO primarily controls the transmission planning process. As vertically integrated utilities, capital investments made by the IOUs tend to be large and lumpy. Together, these characteristics of the industry in Indiana means that some PBR tools may work better than others.

In addition, successful adoption of new regulatory tools in Indiana will depend not only on research-backed expert recommendations, like this report, but also a degree of stakeholder endorsement. In survey responses, utilities and stakeholder groups have expressed reluctance to overhaul the state's current remuneration framework. However, the responses also indicate interest in incremental or optional changes. This feedback suggests that major modifications to the regulatory process, like mandating price caps for all IOUs, would likely meet strong opposition. On the other hand, the regulatory framework could allow utilities the option to file tailored or hybrid indexed cap plans or forecasted MYRPs. Likewise, targeted PIMs could be implemented without a major overhaul of Indiana's existing regulatory practice.

Should the state choose to pursue the adoption of new PBR tools, we recommend collaborating with stakeholders to establish a set of guiding principles like those listed in Section 4.5. Like the Five Pillars, these principles can be used as a basis for evaluating the design and implementation of PBR tools. We have also provided recommendations for best practices in the design of these tools, which are restated in the tables below.

The state's IOUs would benefit from guidance by the IURC regarding what PBR tools will be considered acceptable in future rate applications. Such guidance would increase the likelihood that a given IOU might spend substantial time developing a novel regulatory approach.

10.1 Summary of MYRP Recommendations

Evidence from other jurisdictions indicates that MYRPs can improve utility cost control over time. If properly designed to work within the Indiana context, MYRPs may be able to address stakeholder affordability and cost control concerns. While pure price or revenue caps face implementation obstacles for vertically integrated utilities in RTO regions, hybrid indexed caps may be feasible depending on the design, supporting our recommendation that IOUs be allowed to voluntarily file hybrid PBR plans. Another MYRP option to address cost control concerns, which would align with stakeholder preferences for incremental change, would be to allow the IOUs to voluntarily file forecasted MYRPs. Such an approach is similar to the forward test year option currently available to the state's IOUs but would establish allowed revenue over a longer span of years. Both the hybrid indexed cap approach and the forecasted MYRP approach would reduce the administrative cost of frequent rate cases, if designed properly.

Industry data corroborates stakeholder feedback that input price inflation and increased capital investment needs due to increased environmental regulation have led to higher rates for retail electricity consumers. Cost efficiency incentives through MYRPs may help with affordability but will not resolve all factors driving customer rate increases. This is because, as described in Section 3, most utility costs arise from spending on generation and transmission, which may not be fully within the control of management among the Indiana IOUs. Furthermore, efficiency incentives cannot eliminate the need for Indiana utilities to replace aging capital, insofar as such investments are required for the provision of safe and reliable service.

MYRPs may also reduce the administrative burden of regulation, if rate case stay-out periods lengthen the amount of time between utility rate applications. However, for the reasons stated above, the IURC should not impose a single, standardized incarnation of MYRP on the state's IOUs. Instead, the IOUs should be permitted to file MYRPs based on internal analysis that indicates a high probability of success in maintaining financial strength and service quality while enhancing cost control and reducing administrative burden.

10.2 Summary of PIM Recommendations

A jurisdictional review suggests that the IURC has some flexibility in implementing financial incentives like PIMs that target specific outputs. In some jurisdictions, like in Great Britain, the same set of performance-based financial incentives apply to all utilities. Elsewhere, as in New York, utilities must file individualized PIMs that meet certain criteria outlined by the regulator. In places like North Carolina and Massachusetts, utilities may file company specific PIMs on a voluntary basis.

The first step to developing PIMs is to determine what outputs to target. For example, an incentive could aim to improve reliability or address environmental sustainability. The next step is to establish what metrics can measure these outputs (e.g., SAIDI could be used to measure reliability, while a metric related to renewable connections could be used to measure environmental sustainability). At the design stage, key considerations include: not rewarding or penalizing the utility for results beyond its control; ensuring that the PIM does not have unintended consequences; and setting financial incentives commensurate with the performance outcomes. Stakeholders suggested developing pilot programs to test proposed designs.

We recommend that before instituting any mandatory PIMs, or any PIMs that apply to all utilities, the IURC develop a set of specific policy goals that might be addressed by PIMs and meet with stakeholders to discuss potential benefits and drawbacks of attaching financial incentives to related metrics. In the meantime, the IURC should allow the state's IOUs to propose PIMs on a case-by-case basis as part of the current rate application process.

10.3 Recommendation Tables

The tables below comprise the recommendations presented in this report.

Table 10.1: Summary of Guiding PBR Principles Recommendations

Guiding Principles of PBR	1. The IURC should adopt a set of principles associated with incentive regulation. 2. The development of guiding principles should involve some consensus from utility stakeholders. 3. The IURC may wish to draw from the five principles set forth in this section as a starting point in the development of the state's principles.

Table 10.2: Summary of Revenue Decoupling Recommendations

Revenue Decoupling	Indiana's IOUs already operate with a Lost Revenue Adjustment Mechanism, which shares some properties with revenue decoupling mechanisms. If stakeholders agree that the LRAM is reasonable, we recommend maintaining this approach with no changes.

Table 10.3: Summary of MYRP Recommendations

Recommendations for MYRPs in Indiana	Given that the top concern among stakeholders relates to affordability and cost control, MYRPs that offer cost efficiency incentives may be worth consideration for Indiana's IOUs. As indexed cap PBR frameworks raise feasibility issues for vertically integrated utilities that operate in RTO regions, we do not recommend pure price caps or revenue caps at this time. Hybrid indexed caps may be feasible on a utility-specific basis, wherein each utility may propose a framework that provides incentives while providing sufficient revenue support over a rate case stay-out period. As such, we recommend allowing IOUs to voluntarily file hybrid PBR plans. Stakeholders also stated that incremental change was preferred to major changes to the state's regulatory framework. Forecasted MYRPs could provide an incremental change that offers improved cost efficiency incentives and reduces rate case frequency. We recommend allowing IOUs to voluntarily file three- or four-year forecasted MYRPs.

Table 10.4: Summary of Indexed Cap Recommendations

Indexed Caps	Price or revenue caps may be of interest in Indiana because of the potential to improve cost efficiency among the state's IOUs. However, the vertically integrated organization of the state's electric utilities presents practical complications. If the state pursues indexed caps, we recommend a hybrid approach, as follows: • Only the distribution portions of utility operations operate under the indexed cap; and/or • Capital costs should be either forecast or tracked by a company-specific mechanism. We also recommend adopting the recommendations in Sections 5.1.5.1 through 5.1.5.7 (summarized in this table, below).
Indexed Cap Inflation Factors	If the state of Indiana adopts an indexed cap approach to PBR or a hybrid approach that places some portion of revenue under a cap, we recommend that an inflation factor be included in the PBR formula (I-X). The inflation factor should be established to reflect the electric utility sector's annual input price growth. If an output price measure of inflation is used, the X factor must be adjusted accordingly.
Indexed Cap X Factors	If the state of Indiana adopts an indexed cap approach to PBR or a hybrid approach that places some portion of revenue under a cap, we recommend that an X factor be included in the PBR formula (I-X). This X factor should be calculated from an industry TFP growth or Kahn Methodology analysis.
Indexed Cap Stretch Factors	If the state of Indiana adopts an indexed cap approach to PBR or a hybrid approach that places some portion of revenue under a cap, we recommend that a stretch factor be included in the formula (I-X-S). This stretch factor should be company-specific based on industry cost benchmarking analysis.
Z Factors	If the state of Indiana adopts an indexed cap or forecasted MYRP approach to PBR, or a hybrid approach that places some portion of revenue under a cap, we recommend that a Z factor be included in the PBR framework. The Z factor should be company-specific and have a materiality threshold roughly in line with thresholds seen in other jurisdictions.
Y Factors	If the state of Indiana adopts an indexed cap or forecasted MYRP approach to PBR or a hybrid approach that places some portion of revenue under a cap, we recommend that a Y factor be included in the PBR framework. The Y factor should be company-specific and the costs eligible for Y factor treatment should be clearly defined at the outset of the PBR term.

Capital Factors	If the state of Indiana adopts an indexed cap regulatory framework, we recommend that some form of capital supplement be included on an as-needed basis. The capital factor should be company-specific and the costs eligible for capital factor treatment should be clearly defined at the outset of the PBR term. Economic principles and the guidelines of PBR should be considered in the design of the capital factor.
Reopeners	If the state of Indiana adopts an indexed cap regulatory framework or a forecasted MYRP, we recommend that some form of reopener be included. The reopener provision should be clearly defined, with a clear description of how it would be applied in the event of being triggered.
Earnings Sharing Mechanisms	If the state of Indiana adopts an indexed cap regulatory framework (or a forecasted MYRP), utilities or utility stakeholders may wish to incorporate ESMs to reduce risk. However, if ESMs are adopted, we recommend wide deadbands in order to maintain cost efficiency incentives.
Efficiency Carryover Mechanisms	If the state of Indiana adopts a MYRP regulatory framework, we recommend exploring Efficiency Carryover Mechanisms as a way to maintain cost efficiency incentives over rebasing periods.

Table 10.5: Summary of Forecasted MYRP Recommendations

Forecasted MYRPs	Forecasted MYRPs may be a feasible incremental step toward PBR for Indiana because of the overlap of this kind of framework with current ratemaking practices in the state. Forward test years and phase-in rates are already approved for Indiana's IOUs, and these mechanisms have much in common with forecasted MYRPs. If done correctly, forecasted MYRPs have the potential to improve utility cost efficiency incentives and reduce the regulatory burden of frequent rate cases. If the state pursues forecasted MYRPs, we recommend: • Allow the IOUs to file tailored MYRPs, rather than imposing a common, rigid framework upon each utility. • Forecasted MYRPs may include elements discussed in Section 5.1, regarding indexed caps. For example, exogenous cost factors (Z and Y factors) may be included, as well as reopener provisions.

Table 10.6: Summary of Formula Rate Plan Recommendations

Formula Rate Plans	We do not currently recommend Indiana to pursue formula rate plans. However, if IOUs face major, lumpy investments and the frequency of rate cases becomes a problem, this is an option that could be considered.

Table 10.7: Summary of PIMs Recommendations

Recommendations for PIMs in Indiana	1. We recommend that the IURC allow the state's IOUs to file PIMs as part of future rate applications, to be assessed on a case-by-case basis. 2. We recommend that before instituting any mandatory PIMs, or any PIMs that apply to all utilities, the IURC develop a set of specific policy goals that might be addressed by PIMs and meet with stakeholders to discuss potential benefits and drawbacks of attaching financial incentives to related metrics. Studies may be required to set performance thresholds and the dollar value of financial incentives.

APPENDIX A: GLOSSARY OF TERMS AND ABBREVIATIONS

Table A.1: Glossary of Terms

Term	Definition
Capital Tracker	A periodic rate adjustment mechanism that enables a utility to reflect statutorily defined capital investment it makes in its system in its rates outside of a traditional base rate case. It allows the utility to match its investment and the compensation for that investment in a timely manner.
Cost-of-Service Regulation	An approach to regulation based on the total cost required to own and operate a regulated system. Regulators use a cost-of-service approach to determine a fair price for electric service, by which the aggregate costs for providing each class of service (residential, commercial, and industrial) are determined. Prices are set to recover those costs, plus a reasonable return on the invested capital portion of those costs and allocated based on the sales made to each class.
Demand Response	Voluntary reduction of usage, usually electricity used, by a customer. If a customer agrees to reduce its demand during peak use times, it can get a better overall rate, depending on the utility's tariff on demand response.
Demand Side Management	The planning, implementation, and monitoring of utility activities designed to encourage consumers to modify patterns of electricity usage, including the timing and level of electricity demand.
Distributed Energy Resources	Any resource or activity at or near customer loads that generates energy or reduces energy consumption. Distributed energy resources include customer-site generation, such as solar photovoltaic systems and emergency backup generators, as well as energy efficiency and controllable loads.
Earnings Sharing Mechanisms	Arrangements that divide a utility's earnings above (or below) a predetermined threshold between the utility and its customers, balancing utility profitability with consumer protection.
Efficiency Carryover Mechanism	A mechanism that allows for a portion of productivity gains to be kept by the utility beyond the end of a PBR term. This mechanism incentivizes utilities to pursue continuous efficiency improvements throughout the regulatory term rather than delaying them, as the benefits can "carry over" into subsequent regulatory periods.
Cost Tracker	A periodic rate adjustment mechanism that enables retail rates to be adjusted outside the context of a base rate case to reflect changes in operating expenses. These adjustments allow the utility to recover what it has spent on a dollar-for-dollar basis.
Formula Rates	A regulatory framework that sets establishes cost-based rates over a time period without the need for annual rate applications. Electric rates determined by a formula rate plan are based on a pre-determined revenue requirement formula and are updated each year with the inputs based on utility's most recent financial data.
Multi-Year Rate Plans	Rate-regulation frameworks that set rates or revenues for utilities over multiple years, typically 3-5 years, to provide predictability and incentivize cost efficiency.
Performance Incentive Mechanisms	Regulatory tools that link utility revenues or returns to achievement of specific performance targets, such as reliability, customer service, or environmental goals.

Term	Definition
Performance-Based Regulation	Any form of alternative regulation that ties company earnings to performance on metrics set by the regulator, rather than to strict cost-recovery of invested capital and operating expenses.
Price Cap	A method of rate-regulation that places a limit on the prices a utility can charge, typically adjusted annually for inflation and expected efficiency improvements.
Rate Base	The value of property upon which a utility is permitted to earn a specified rate of return. It is established by a regulatory authority and generally represents the value of property purchased and used by the utility in providing service (less accumulated depreciation).
Rate Case	A proceeding, usually before a regulatory commission, involving the rates, revenues, and policies of a public utility.
Rebasing	The periodic process of resetting or adjusting a utility's revenue requirement through a formal cost-of-service rate case. This term is commonly used in Performance-Based Regulation to describe the process to determining revenue requirement between Multi-Year Rate Plans.
Regulatory Lag	The lapse of time between when costs are incurred and when costs are allowed to be recovered. Most often this term refers to the period between a petition for a rate increase and formal action by a regulatory body.
Revenue Cap	A regulatory approach that sets a maximum allowed revenue for a utility, regardless of sales volume, adjusted for external factors such as inflation and efficiency factors.
Revenue Decoupling	A mechanism that separates a utility's revenues from its energy sales volume, reducing the incentive to increase energy sales and supporting energy efficiency initiatives.
Revenue Requirement	The annual revenue that the utility is entitled to collect (as modified by adjustment clauses). Under traditional regulation, the revenue requirement equals the sum of operation and maintenance expenses, depreciation, taxes, and a return on rate base.
Test Years	A specific period chosen to demonstrate a utility’s need for a rate increase. It may or may not include adjustments to reflect known and measurable changes in operating revenues, expenses, and rate base. A test year can be either historical or projected (often called “future” or “forecasted” test year).

Table A.2: Glossary of Abbreviations

Abbreviated Term	Full Term	Abbreviated Term	Full Term
ARM	Attrition Relief Mechanism	FRP	Formula Rate Plan
AUC	Alberta Utilities Commission	FWI	Fixed Weighted Index
BCUC	British Columbia Utilities Commission	GDP-PI	Gross Domestic Product Price Index
CA Energy Consulting	Christensen Associates Energy Consulting	HECO	Hawaiian Electric Company
CAC	Citizen Action Coalition	I&M	Indiana Michigan Power Company
CAIDI	Customer Average Interruption Duration Index	INDIEC	Indiana Industrial Energy Consumers
CAPEX	Capital Expenses	IOU	Investor-Owned Utility
COSR	Cost of Service Regulation	IPC	Idaho Power Company
CPI	Consumer Price Index	IURC	Indiana Regulatory Commission
CSPI	Customer Service Performance Mechanism	MISO	Midcontinent Independent System Operator
DART	Days Away, Restricted, or Transferred (DART)	MYRP	Multi-Year Rate Plan
DEC	Duke Energy Carolinas	NYPSC	New York Public Service Commission
DER	Distributed Energy Resource	OPEX	O&M Expenses
DSM	Demand Side Management	OUCC	Office of Utility Consumer Counselor
EAM	Earnings Adjustment Mechanism	PBR	Performance Based Regulation
ECM	Efficiency Carryover Mechanism	PBR3	Third Generation Performance Based Regulation in Alberta, Canada
EE	Energy Efficiency	PIM	Performance Incentive Mechanism
EPCOE	Evaluation Period Cost of Equity	REI	Reliable Energy Indiana
EPRM	Exceptional Project Recovery Mechanism	RIIO	Revenue using Incentives to deliver Innovation and Outputs
ESM	Earnings Sharing Mechanism	ROE	Return on Equity
FAC	Fuel Adjustment Clause	RPM	Reliability Performance Mechanism
FBC	FortisBC, Inc.	RPS-A	Renewable Portfolio Standard-Accelerated
FCA	Fixed Cost Adjustment	SAIDI	System Average Duration Frequency Index
FCC	Fixed Costs per Customer	SAIFI	System Average Interruption Frequency Index
FCE	Fixed Cost per Energy	TDSIC	Transmission, Distribution, and Storage System Improvement Charge
FEI	FortisBC Energy Inc.	TOTEX	Total Expenditure
FERC	Federal Energy Regulatory Commission	United	Advanced Energy United
FFR	Fast Frequency Response	VOLL	Value of Lost Load
FRED	Federal Reserve Economic Data	VTOU	Voluntary Time of Use

APPENDIX B: INDEXED CAP DERIVATIONS

B.1 Price Cap Derivation

The derivation for a utility's cap in price growth follows from the theory of competitive markets, as PBR attempts to induce growth in price that one would observe if the regulated company were in fact operating in a competitive market. In competitive markets, firms earn zero economic profit[149]. This is generally understood best by example; suppose a firm operates in a competitive market and is able to rent capital at a low price and use this rented capital along with labor and materials to produce goods at an output price that allows for positive economic profit. In this case, profit-seeking competing firms will enter the market and copy this strategy, bidding up the price of capital until profits are zero. Thus, it must be the case that revenues equal economic cost:

$$Revenue = Economic\ Cost$$

$$\sum p_i q_i = \sum w_j z_j$$

Where p_i is the price of output i, q_i is the number of units of output i, w_j is the price of input j, z_j is the number of units of input j, and the notation $\sum x_i$ is shorthand for $x_1 + x_2 + \ldots x_n$ if i takes on values from 1 to n. For example, the utility's three billable outputs might be energy (KWh), demand (KW) and total customers. In the first case, the utility has a price per KWh (p_{KWh}) and a total KWh delivered to customers (q_{KWh}) that when multiplied together yields total revenue from energy sold. On the input side, as an example, the utility might have three inputs: labor, capital, and materials. If the utility hires z_{Labor} employees and pays a wage of w_{Labor}, the cost of labor can be calculated by multiplying these terms together. Therefore, its revenue is $p_{KWh}q_{KWh}$ + $p_{demand}q_{demand}$ + $p_{customers}q_{customers}$ and its costs are $w_{labor}z_{labor}$ + $w_{capital}z_{capital}$ + $w_{materials}z_{materials}$, which can be written a compact way as shown above, for i in $[KWh, demand, customers]$ and j in $[labor, capital, materials]$.

The task of calibrating a price cap is to figure out how prices should move in response to exogenous changes in input prices and outputs (say, demand and customer growth) to allow the utility enough revenue to cover its costs. This can be achieved by studying how the revenue equals cost relationship changes over time when prices, outputs, and inputs change:[150]

$$\sum \dot{p}_i q_i + \sum p_i \dot{q}_i = \sum \dot{w}_j z_j + \sum w_j \dot{z}_j$$

Roughly speaking, the notation $\dot{x}$ can be interpreted as the change in x over time.[151] To convert this expression to growth rates rather than level changes, we can begin by multiplying and

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[149] Economic profit includes opportunity cost. For instance, if a firm owns its capital, the amount it can earn in rent payments from leasing it to businesses should be included as a cost.

[150] This is derived by totally differentiating the revenue equals cost expression with respect to time.

[151] Technically, it is the derivative of x with respect to time, or dx/dt.

dividing each term by level of the variable that has been differentiated, since this ratio is 1 and thus the equality still holds:

$$\sum \dot{p}_i q_i \frac{p_i}{p_i} + \sum p_i \dot{q}_i \frac{q_i}{q_i} = \sum \dot{w}_j z_j \frac{w_j}{w_j} + \sum w_j \dot{z}_j \frac{z_j}{z_j}$$

We can then divide the left-hand side by total revenue and the right-hand side by total cost, since these quantities are equal and so the equality still holds. We can then rewrite the expression in terms of revenue and cost shares, noting that

$r_i = \frac{q_i p_i}{Revenue}$, or output $i's$ revenue share, and

$c_i = \frac{w_j z_j}{Cost}$, or input $j's$ cost share

Doing so changes the expression to

$$\%\Delta Revenue = \%\Delta Cost$$

or,

$$\sum r_i \frac{\dot{p}_i}{p_i} + \sum r_i \frac{\dot{q}_i}{q_i} = \sum c_j \frac{\dot{w}_j}{w_i} + \sum c_j \frac{\dot{z}_j}{z_i}$$

The first term is the sum of the percentage changes in output prices, where each price is weighted by its share in revenue. It can be interpreted as the percentage change in the price index.[152] The other terms take the same form, and represent percentage changes in the output index, the input price index, and the input index, respectively. Rewriting to make this clear,

$$\%\Delta P + \%\Delta Q = \%\Delta W + \%\Delta Z$$

Solving for $\%\Delta P$,

$$\%\Delta P = \%\Delta W - (\%\Delta Q - \%\Delta Z)$$

$$\%\Delta P = I - X$$

where $I = \%\Delta W$ and $X = \%\Delta Q - \%\Delta Z$

There are several possible choices for X. The first choice is the company's own projected productivity growth. In this case, the company will earn zero profit essentially by design. Another choice, which is the standard approach, is to let X be the average productivity growth in the industry. This latter choice forces the company to match the industry's productivity rate in order to at least break even. However, note that neither choice ideally emulates competitive markets, since the industry productivity rate is not reflective of a competitive market. This is an important part of the motivation behind the stretch factor, discussed above.

[152] This percentage change is referred to as a Tornqvist index.

In some jurisdictions it is common to use a measure of output inflation rather than input inflation. In this case, the price cap can be derived by noting that, if one assumes the economy as a whole is competitive, the same relationship holds for the economy:

$$\%\Delta P_{econ} = I_{econ} - X_{econ}$$

$\%\Delta P_{econ}$ is output price inflation, which is the inflation measure used for the utility's price cap in this case. An example of $\%\Delta P_{econ}$ is the growth rate of the GDP-PI. A measure of economy-wide total factor productivity growth is estimated annually, and so together with the GDP-PI, I_{econ} can be recovered as the sum of these two growth rates based on the above equation. Combining this equation with same equation derived for the average company in the industry (with the X that incentivizes the firm to at least match the productivity of the average company), the two equations can be subtracted to yield

$$\%\Delta P_{ind} - \%\Delta P_{econ} = (I_{ind} - I_{econ}) - (X_{ind} - X_{econ})$$

$$\%\Delta P_{ind} = \%\Delta P_{econ} - [(I_{econ} - I_{ind}) + (X_{ind} - X_{econ})]$$

which is the appropriate price cap when a measure of output price inflation is used.

In summary, there are two common price caps, depending on whether an input or output price inflation measure is used. When the appropriate measure of input price inflation is used, the cap is

$$\%\Delta P = I_{ind} - X_{ind}$$

When a measure of output price inflation like the growth rate in the GDP-PI is used, the cap is

$$\%\Delta P = \%\Delta P_{econ} - [(I_{econ} - I_{ind}) + (X_{ind} - X_{econ})]$$

B.2 Revenue Cap Derivation

In B.1, we derived the formula for the price cap:

$$\%\Delta P = I - X$$

This was derived by noting that, in competitive markets,

$$\%\Delta Revenue = \%\Delta Cost$$

$$\%\Delta P + \%\Delta Q = \%\Delta W + \%\Delta Z$$

Thus, $\%\Delta Revenue = \%\Delta P + \%\Delta Q$.

For a given price cap $\%\Delta P$, adding on $\%\Delta Q$ yields the corresponding revenue cap $\%\Delta Revenue$. This factor $\%\Delta Q$ is often called the "growth factor", and is represented by the term *G*.

APPENDIX C: SURVEY QUESTIONS

C.1 Initial Survey to Indiana Stakeholders

1. Does your organization consider the adoption of Multi-Year Rate Plans advisable in Indiana? Please explain the reasons for your position. If your organization requires more information before forming a position, what additional information is needed?

2. Does your organization consider the adoption of Performance Incentive Mechanisms advisable in Indiana? Please explain the reasons for your position. If your organization needs more information before forming a position, what additional information is needed?

3. Are there any specific aspects or details about Multi-Year Rate Plans or Performance Incentive Mechanisms, beyond what is stated above, that your organization needs to provide comprehensive feedback on these mechanisms?

C.2 Follow-up Survey to Indiana Stakeholder

C.2.1 Utility Stakeholders

1. Did the workshop on October 17th provide helpful information regarding the IURC's plans to evaluate the applicability of PBR in Indiana?

2. Did your organization feel it had the opportunity to provide comments and ask questions during the workshop?

3. What aspects of the workshop did you find valuable and what areas do you feel could be improved?

4. What goals and outcomes related to electric utility services should be pursued through regulation in Indiana?

5. How well does the current rate-regulation framework in Indiana facilitate success in the following areas? (Very well/Adequately/Neutral/Poorly/Very Poorly)
    a. Reliability
    b. Resilience
    c. Stability
    d. Affordability
    e. Environmental Sustainability
    f. Utility cost control
    g. Regulatory efficiency
    h. Customer service/connection time
    i. Financial health of the utility
    j. Adaptability to the energy transition (e.g., retirement of coal generation facilities; adoption of distributed energy resources; electrification)

6. Will the current rate-regulation framework in Indiana remain appropriate for optimizing utility services in the following areas, given the transition from coal power generation and given the energy transition (e.g., adoption of distributed energy resources; electrification)? (Yes/No) If no, please explain what improvements could be made to the state's regulatory framework that would offer improvements to the status quo.
    a. Reliability
    b. Resilience
    c. Stability
    d. Affordability
    e. Environmental Sustainability
    f. Utility cost control
    g. Regulatory efficiency
    h. Customer service/connection time
    i. Financial health of the utility
    j. Adaptability to the energy transition (e.g., retirement of coal generation facilities; adoption of distributed energy resources; electrification)
7. Have your organization's customer rates increased at a faster pace than the historical average over the last decade? If so, why?

8. What could be done to increase cost efficiency?

9. The utility industry is capital intensive. Some perceive that capital investments by utilities are made in a cyclical pattern, such that during some years (or decades), substantial investment occurs, while in other years, less investment occurs. Does your organization perceive a capital building cycle in your business? If so, at what stage is your organization in the building cycle? What are the company's expected major investments over the next decade?

10. With what frequency has your utility filed rate applications since the year 2000? Do you expect this same frequency in the coming years?

11. Would you support a regulatory regime that <u>allows the option</u> to use a MYRP on the state's investor-owned utilities, meaning three or more years between rate applications? (This could mean forecasting revenues over a three-year period, operating under a price or revenue cap, or setting rates annually based on a cost-of-service formula.) Explain why or why not.

12. Does your utility have the ability to conduct detailed revenue requirement forecasts at the FERC account level, such that test year revenue requirements could be established on a forecast basis over three or more years? If not, could such revenue requirement forecasts be reasonably determined?

13. Consider a "pure price cap", under which customer base rates are set according to the company's total revenue requirement in a rate case and then adjusted each year only according to a formula based on inflation and industry productivity. Under a "pure price cap", the utility would not have capital trackers like TDSIC, but would retain flow-through mechanisms like the Fuel Adjustment Clause. Could your utility operate under a "pure price cap" over a five-year period without filing a rate application? Why or why not?

14. Consider a "limited price cap", under which customer base rates are set in a rate case according to a *portion* of the company's revenue requirement, excluding existing capital trackers. Rates recovering this limited portion of the utility's are then adjusted each year only according to a formula based on inflation and industry productivity. Under a "limited price cap", the utility would retain capital trackers like TDSIC and flow-through mechanisms like the Fuel Adjustment Clause. Could your utility operate under a "limited price cap" over a five-year period without filing a rate application? Why or why not? What portion of the utility's revenue requirement should be excluded from the price cap adjustment and recovered through external trackers?

15. Consider a "pure revenue cap", under which customer base rates are set in a rate case according to the company's total revenue requirement. Then, the revenue requirement is adjusted each year only according to a formula based on inflation and industry productivity, and rates are set based on this updated revenue requirement. Under a "pure revenue cap", the utility would not have capital trackers like TDSIC, but would retain flow-through mechanisms like the Fuel Adjustment Clause. Could your utility operate under a "pure revenue cap" over a five-year period without filing a rate application? Why or why not?

16. Consider a "limited revenue cap", under which customer base rates are set in a rate case according to a *portion* of the company's revenue requirement, excluding existing capital trackers. The revenue requirement pertaining to this limited portion of the utility's costs is then adjusted each year only according to a formula based on inflation and industry productivity. Under a "limited revenue cap", the utility would retain capital trackers like TDSIC and flow-through mechanisms like the Fuel Adjustment Clause. Could your utility operate under a "limited revenue cap" over a five-year period without filing a rate application? Why or why not? What portion of the utility's revenue requirement should be excluded from the revenue cap adjustment and recovered through external trackers?

17. Would you expect your utility to obtain financial benefits from operating under some form of price (or revenue) cap? Why or why not?

18. Would you expect your customers to obtain benefits from operating under some form of price (or revenue) cap? Why or why not?

19. Would you support financial rewards (i.e., PIMs) for utilities that provide superior service quality or penalties for utilities that provide sub-par service quality, as established by specific metrics? Does your opinion change if the PIMs are not required or if the PIMs are specific to the utility.

20. How would you define success or failure for a performance-based regulation mechanism such as a MYRP or PIM?

21. Does your organization agree that incremental updates to Indiana's existing regulatory structure would be a better approach to address the goals of both Indiana utilities and consumers, compared to requiring the utilities to operate under some form of MYRP? If so, what incremental updates could be considered, and what goals would these updates help to address?

22. Do you have any additional information or comments to share regarding the exploration of performance-based regulation for Indiana utilities?

23. Would you find value in a second workshop? If so, what topic areas would you want to discuss?

C.2.2 Non-Utility Stakeholders

1. Did the workshop on October 17th provide helpful information regarding the IURC's plans to evaluate the applicability of PBR in Indiana?

2. Did your organization feel it had the opportunity to provide comments and ask questions during the workshop?

3. What aspects of the workshop did you find valuable and what areas do you feel could be improved?

4. What goals and outcomes related to electric utility services should be pursued through regulation in Indiana?

5. How well does the current rate-regulation framework in Indiana facilitate success in the following areas? (Very well/Adequately/Neutral/Poorly/Very Poorly)
    a. Reliability
    b. Resilience
    c. Stability
    d. Affordability
    e. Environmental Sustainability
    f. Utility cost control
    g. Regulatory efficiency
    h. Customer service/connection time
    i. Financial health of the utility
    j. Adaptability to the energy transition (e.g., retirement of coal generation facilities; adoption of distributed energy resources; electrification)

6. Will the current rate-regulation framework in Indiana remain appropriate for optimizing utility services in the following areas, given the transition from coal power generation and given the energy transition (e.g., adoption of distributed energy resources; electrification)? (Yes/No) If no, please explain what improvements could be made to the state's regulatory framework that would offer improvements to the status quo.
    a. Reliability
    b. Resilience
    c. Stability
    d. Affordability
    e. Environmental Sustainability
    f. Utility cost control
    g. Regulatory efficiency
    h. Customer service/connection time
    i. Financial health of the utility

j. Adaptability to the energy transition (e.g., retirement of coal generation facilities; adoption of distributed energy resources; electrification)

7. Have rates increased at a faster pace than the historical average over the last decade? If so, why?

8. What could be done to improve affordability for customers?

9. Would you support a regulatory regime that allows the option to use a MYRP on the state's investor-owned utilities, meaning three or more years between rate applications? (This could mean forecasting revenues over a three-year period, operating under a price or revenue cap, or setting rates annually based on a cost-of-service formula.) Explain why or why not.

10. Do you support utilities operating under a price cap (or revenue) cap over a five-year period, where prices (or revenue requirements) are adjusted each year according to a formula based on inflation and industry productivity? Why or why not?

11. If utilities established a revenue requirement forecast for three or more years, would it be more burdensome to validate the reasonableness of such forecasts compared to evaluating a single future test year? What additional information would utilities need to provide to assist in the evaluation of such forecasts?

12. Would you expect a utility to obtain financial benefits from operating under some form of price (or revenue) cap? Why or why not?

13. Would you expect customers to obtain benefits from a utility operating under some form of price (or revenue) cap? Why or why not?

14. Would you support financial rewards (i.e., PIMs) for utilities that provide superior service quality or penalties for utilities that provide sub-par service quality, as established by specific metrics? Does your opinion change if the PIMs are not required or if the PIMs are specific to the utility.

15. How would you define success or failure for a performance-based regulation mechanism such as a MYRP or PIM?

16. Does your organization agree that incremental updates to Indiana's existing regulatory structure would be a better approach to address the goals of both Indiana utilities and consumers, compared to requiring the utilities to operate under some form of MYRP? If so, what incremental updates could be considered, and what goals would these updates help to address?

17. Do you have any additional information or comments to share regarding the exploration of performance-based regulation for Indiana utilities?

18. Would you find value in a second workshop? If so, what topic areas would you want to discuss?

C.2.3 Regulators

1. What specific PBR mechanisms are in place in your jurisdiction? (e.g., Multi-Year Rate Plans (MYRPs), Performance Incentive Mechanisms (PIMs), Revenue Caps, Price Caps, etc.)

2. Was PBR imposed upon utilities by the regulator, or did the utilities request PBR?

3. How did your commission determine the appropriate PBR tools for your jurisdiction? (e.g., if your jurisdiction has PIMs, how were these chosen? If your jurisdiction has some form of MYRP, how was it decided what MYRP approach was appropriate?)

4. What has been the feedback from stakeholders (e.g., advocacy groups, utilities, and customers) since PBR has been implemented? (Generally positive; neutral; or negative.)

5. How has your jurisdiction handled revenue recovery for major capital project under PBR (e.g., capital trackers, "K-bar", or other mechanisms)? What have been the benefits and drawbacks of this approach?

6. If your region no longer operates under PBR, what PBR mechanisms were used, and what were the reasons for moving away from PBR?

7. Does your commission define best practices for the design of performance-based regulation mechanisms such as a MYRPs or PIMs? If so, what are these best practices? (Please provide relevant documentation, if it's helpful.)

8. What have been the most significant benefits and challenges associated with PBR in your region?

9. Are there any unintended consequences or lessons learned from implementing PBR?

10. Did the implementation of PBR increase or decrease the regulatory burden for your commission?

11. Has your region made any modifications to its PBR framework since implementation? If so, what changes were made and why?

12. Have you observed changes in utility investment strategies, customer service, customer bills, or innovation as a result of PBR?

13. How has your commission incorporated emerging challenges such as grid modernization, electrification, and distributed energy resources into the design of your PBR framework?

APPENDIX D: PBR PRINCIPLES IN OTHER JURISDICTIONS

D.1 Alberta

Gas and electric distribution utilities in the province of Alberta have operated under PBR for over a decade. In the original decision that organized PBR in the province, the Alberta Utilities Commission published the following guiding principles:[153]

Principle 1. A PBR plan should, to the greatest extent possible, create the same efficiency incentives as those experienced in a competitive market while maintaining service quality.

Principle 2. A PBR plan must provide the company with a reasonable opportunity to recover its prudently incurred costs including a fair rate of return.

Principle 3. A PBR plan should be easy to understand, implement and administer and should reduce the regulatory burden over time.

Principle 4. A PBR plan should recognize the unique circumstances of each regulated company that are relevant to a PBR design.

Principle 5. Customers and the regulated companies should share the benefits of a PBR plan.

D.2 British Columbia

The BCUC determined that the principles listed below should guide its assessment of the efficacy of the MYRPs proposed by FortisBC Energy Inc. (FEI) and FortisBC, Inc. (FBC) (together, FortisBC).[154] These principles align closely with the principles adopted by the Alberta Utilities Commission (AUC) for the PBR plans in effect in Alberta. As noted by the AUC, there is a high degree of consensus on the principles that should guide the development of PBR.

1. The PBR plan should, to the greatest extent possible, align the interests of customers and the utility; customers and the utility should share in the benefits of the PBR plan.

2. The PBR plan must provide the utility with a reasonable opportunity to recover its prudently incurred costs including a fair rate of return.

3. The PBR plan should recognize the unique circumstances of the company that are relevant to the PBR design.

4. The PBR plan should maintain the utility's focus on maintaining safe, reliable service and customer service quality while creating the efficiency incentives to continue with its productivity improvement culture.

[153] Alberta Utilities Commission, *Regulated Rate Initiative – PBR Principles*, AUC Bulletin 2010-20, July 15, 2010, p. 2.

[154] British Columbia Utilities Commission, *Application for Approval of a Multi-Year Rate Plan for the Years 2020 through 2024*, Decision and Orders G-165-20 and G-166-20, June 22, 2020, p. 168.

5. The PBR plan should be easy to understand, implement, and administer and should reduce the regulatory burden over time.

D.3 Ontario

In its Renewed Regulatory Framework, the Ontario Energy Board concluded the following outcomes are appropriate for consideration when evaluating utility rate applications.[155]

1. Customer Focus: services are provided in a manner that responds to identified customer preferences;
2. Operational Effectiveness: continuous improvement in productivity and cost performance is achieved; and utilities deliver on system reliability and quality objectives;
3. Public Policy Responsiveness: utilities deliver on obligations mandated by government (e.g., in legislation and in regulatory requirements imposed further to Ministerial directives to the Board); and
4. Financial Performance: financial viability is maintained; and savings from operational effectiveness are sustainable

D.4 Massachusetts

In addition, the Department established a number of factors it would weigh in evaluating incentive proposals. These factors provide that a well-designed incentive proposal should:[156]

1. Comply with Department regulations, unless accompanied by a request for a specific waiver;
2. Be designed to serve as a vehicle to a more competitive environment and to improve the provision of monopoly services;
3. Not result in reductions of safety, service reliability, or existing standards of customer service;
4. Not focus excessively on cost recovery issues;
5. Focus on comprehensive results;
6. Be designed to achieve specific, measurable results; and
7. Provide a more efficient regulatory approach, thus reducing regulatory and administrative costs. These objectives mesh with the guiding principles of PBR established in other jurisdictions.

[155] Ontario Energy Board. *Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach*. October 18, 2012. p. 57.
[156] Massachusetts D.P.U. 94-158, at 57.

D.5 Hawaii

PBR Guiding Principles:[157]

1. A customer-centric approach. A PBR framework should encourage the expanding opportunities for customer choice and participation in all appropriate aspects of utility system functions, including verifiable "day-one" savings for customers.
2. Administrative efficiency. PBR offers an opportunity to simplify the regulatory framework and enhance overall administrative
3. Utility financial integrity. The financial integrity of the utility is essential to its basic obligation to provide safe and reliable electric service for its customers and PBR framework is intended to preserve the utility's opportunity to earn fair return on its business and investments, while maintaining attractive utility features such as a low cost of capital.

[157] Hawaii Public Utilities Commission. Decision and Order No. 36326, filed May 23, 2019 at 6

APPENDIX E: QUALIFICATIONS OF THE PROJECT TEAM AND DUTY OF INDEPENDENCE

E.1 Qualifications of the Project Team

Christensen Associates and its wholly owned subsidiary, Christensen Associates Energy Consulting (CA Energy Consulting), have over 40 years of experience in the design and application of incentive regulation plans across network industries, including electricity, gas, telecommunications, and postal industries.[158] The key team members for the project were Mr. Nicholas Crowley and Dr. Daniel McLeod.

Mr. Nicholas Crowley, CFA, is a Vice President with Christensen Associates and has been with the firm since 2016. He has filed testimony on incentive regulation in both the United States and Canada and has filed reports and testimony on incentive regulation in Ontario, Alberta, British Columbia, New Hampshire, Maine, and Massachusetts. Prior to joining this firm, Mr. Crowley was an economist in the Department of Pipeline Regulation at the Federal Energy Regulatory Commission (FERC), where he assisted with energy industry benchmarking, the price cap regulation of oil pipelines, and the review and evaluation of natural gas pipeline rate cases. In these roles, Mr. Crowley worked extensively with FERC data, and other federal data, for the development of cost benchmarks for power systems, in measuring industry TFP growth, and the development of incentive regulation plans. Mr. Crowley has a Master of Science degree in economics and a Bachelor of Science degree in economics, both from the University of Wisconsin-Madison. He is a CFA charterholder.

Dr. Daniel McLeod is an Economist at Christensen Associates and has been with the firm since 2021. During this time, he has been involved with electric and gas utility PBR proceedings in the United States and Canada. He received his Ph.D. in economics from the University of Wisconsin-Madison in 2021, with a focus in empirical industrial organization. He has worked on litigation cases spanning several industries, including agriculture, electronics, and telecommunications.

Economist Andis Romanovs-Malovrh and Staff Economist Corey Goodrich also contributed invaluable research support toward the completion of this report.

E.2 Duty of Independence

CA Energy Consulting has undertaken the work contained in this report understanding that we have a duty to provide opinion evidence to the Commission that is fair, objective, and non-partisan. This report reflects the independent opinion of the authors.

[158] Network industries are characterized by product distribution lines connected by nodes that serve multiple distribution lines. Examples include electric and gas utilities, telecommunications, railroads, and the U.S. Postal Service.