<u>Indiana Investor-Owned Electric Utilities' 11/22/2024 Responses to PBR Survey Questions</u>

These responses are submitted on behalf of the following companies: Indianapolis Power & Light Company d/b/a AES Indiana, Southern Indiana Gas and Electric Company d/b/a CenterPoint Energy Indiana South, Duke Energy Indiana, LLC, Indiana Michigan Power Company, and Northern Indiana Public Service Company LLC (collectively the "Indiana Investor-Owned Electric Utilities" or the "Indiana IOU Electrics"). However, each company also reserves the right to file separate responses on behalf of itself.

<u>Stakeholder Workshop:</u>

If you attended the IURC Performance-Based Regulation ("PBR") Study Stakeholder Engagement Workshop that was held on October 17th, please answer the following two questions. If not, skip to the next section.

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

   Response:

   Yes, the Indiana Investor-Owned Electric Utilities found the workshop very informative.

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

   Response:

   Yes.

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

   Response:

   Christensen Associates provided a detailed presentation and explanation, including examples which assisted in the utilities' understanding of what the Indiana PBR Study involves. There was open Q&A which was helpful, however, now that the utilities have a better understanding of what the PBR study involves, follow-up workshops would allow for more questions, discussion, and potential feedback around multi-year rate plans (MYRPs) and performance incentive mechanisms (PIMs).

   The discussion clarified various alternative regulatory frameworks and emphasized that there are no two structures that are identical; programs are tailored to a state's individual needs. There could have been more discussion comparing and contrasting Indiana's current structure with performance-based ratemaking (PBR)/multi-year rate plans, highlighting similarities and differences.

Future sessions could include additional details about guardrails, re-openers or off-ramps, and other modifications to MYRPs and PIMs deployed by other states, and lessons learned from states with experience with PBR mechanisms.

Current Regulatory Framework:

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

   Response:

   Based on guidance from the Indiana General Assembly and longstanding caselaw, the Indiana Investor-Owned Electric Utilities submit that the goals of Indiana utility regulation should include Indiana's "Five Pillars" — reliability, resiliency, stability, affordability, and environmental sustainability — plus safety, utility financial integrity, fair allocation of costs among customer classes, sound rate designs, and high quality customer service. We also believe that regulatory flexibility is important to achieving many of these goals. Regulatory flexibility recognizes that each utility is inherently different and acknowledges that utility-specific proposals are often required to address a given utility's unique issues and changing conditions.

2. **How well does the current rate-regulation framework in Indiana facilitate success in the following areas? (Very well/Adequately/Neutral/Poorly/Very Poorly)**

   Response:

   a. **Reliability** — Very well. The reliability of Indiana's Investor-Owned Electric Utilities is excellent. Note that each Indiana IOU Electric is required to file a reliability report with the IURC, and the IURC compiles the utilities' historical performance under the System Average Interruption Frequency Index (SAIFI), System Average Interruption Duration Index (SAIDI), and Customer Average Interruption Duration Index (CAIDI) metrics. See https://www.in.gov/iurc/files/Electric-Utility-Reliability-Report-2023.pdf.

      In addition, each Indiana IOU Electric annually submits a performance metrics report to the Commission, which includes the utility's reliability performance and typically addresses reliability indices (i.e., SAIDI, SAIFI, and CAIDI), major event day data, overhead line maintenance, vegetation management investment, and generation performance metrics such as Equivalent Availability Factor (EAF) and Equivalent Forced Outage Rate (EFOR).

      In addition, as a routine matter included in each individual Indiana IOU Electric base rate case filing, and in support of Indiana's Five Pillars of electric utility service, the utility addresses and provides support for current investments and expenses it is incurring for generation resources, as well as the need for additional investments in the future test year, to ensure generation resources are providing safe and reliable service to customers. Utilities also provide support, in base rate cases and/or transmission, distribution, and storage system improvement charge (TDSIC) plan cases, for continued improvements to the resiliency, reliability, and stability of the distribution and/or transmission systems and the necessary investments to improve reliability to the end-use customers.

The Electric IOUs' diverse generation fleet continues to present a reliable, affordable, and increasingly clean mix of resources within MISO and PJM. MISO has also implemented a seasonal capacity construct and other accreditation changes to bolster resource adequacy. PJM is also instituting accreditation changes and continues to evaluate seasonal constructs.

b. **Resilience** — Very well. Indiana's investor-owned electric utility systems continue to demonstrate resilience — the ability to withstand and recover from extraordinary events.

Similar to (a) above, resiliency is addressed as a routine matter in each individual Indiana IOU Electric base rate case and/or TDSIC plan case and supports the Five Pillars of electric utility service. Within such case(s), the utility addresses and provides support for investments in its transmission and/or distribution systems to maintain and improve reliability and resiliency, as well as enhance safety and leverage technology to benefit the grid. For example, as part of I&M's future test-year base rate case filings, it presents its Distribution Management Plan, which is a comprehensive, forward-looking capital and operations plan under which I&M will continue to make significant investments to maintain and improve reliability and resiliency of its distribution system, to enhance safety, and to leverage technology to benefit the grid. I&M provides support for its Distribution Management Plan key objectives of maintaining and improving safety, improving the customer experience, enhancing system resiliency, accommodating new loads and supply sources at the distribution level, maintaining system flexibility, and enhancing data collection and utilization.

In addition, the reliability and resilience of the electric system, in terms of major events, is shown in the IURC reliability report. See https://www.in.gov/iurc/files/Electric-Utility-Reliability-Report-2023.pdf. See also the presentations from the IURC's 09/22/2023 Storm Response meeting. https://secure.in.gov/iurc/files/NIPSCO-IURC-Storm-Response-Meeting-9.22.23.pdf
https://secure.in.gov/iurc/files/IURC-Storm-Response-2023-Duke-Energy-Indiana.pdf
https://secure.in.gov/iurc/files/2023-Storm-Response-Meeting-CEI-South-FINAL.pdf
https://secure.in.gov/iurc/files/Indiana-Michigan-Power_Storm-Response-Presentation.pdf

Also, the current rate-regulation framework provided by the TDSIC statute encourages investments related to safety, reliability, modernization, and economic development. The Commission's 2024 Annual Report provides an update on the Indiana IOU Electrics that currently have approved TDSIC plans. The Indiana IOUS Electrics with approved plans track and provide updates in docketed proceedings to ensure the plan is delivered in accordance with the utility's objectives. As one example, one of Duke Energy Indiana's objectives in its approved TDSIC 2.0 plan is to improve resiliency. Investments to advance hardening and resiliency of the transmission and distribution grid are occurring under this plan. Hardening physically changes the infrastructure to make it less susceptible to damage, while resiliency makes the grid smarter and better able to recover from events more quickly. Examples of TDSIC 2.0 hardening programs include line rebuilds, pole upgrades and replacements, installation of intermediate dead-end structures, targeted underground, transformer replacements, and uprating 4kV lines to 12kV. Duke Energy Indiana's TDSIC 2.0 resiliency programs include self-optimizing grid and automated lateral device investments, as well as installing Supervisory Control and Data Acquisition ("SCADA") at transmission switches and substations.

c. **Stability** — Very well. The stability of Indiana's IOU Electrics' systems remains excellent. Notably, the transmission and generation infrastructure is highly integrated in Indiana, which supports stability. In addition, the RTO and IRP processes ensure adequate generation resources, and stability is in part a function of sufficient dispatchable generation capacity to maintain system frequency and voltage during contingencies and peak loads.

Similar to reliability and resiliency, stability is also a routine matter supported in each individual Indiana IOU Electric base rate case and/or TDSIC plan case and supports the Five Pillars of electric utility service. For example, in I&M's future test-year base rate case filings, it addresses and provides support for current investments and expenses it is incurring for generation resources, as well as the need for additional investments in the future test-year, to ensure resources are providing safe, reliable, and stable service to customers. Additionally, as part of its base rate case filings, I&M supports the continued improvements to the resiliency, reliability, and stability of the distribution system and the necessary investments to improve reliability to the end-use customers.

The Indiana IOU Electrics have made both TDSIC and non-TDSIC investments that contribute to the operational stability of the system and prevent outages. As one example, Duke Energy Indiana has realized improvement in generation performance as a result of reliability plan execution during large maintenance outages which occurred in 2022 and 2023. New investments are being made by the Indiana IOU Electrics, maintaining stability of electric service and enabling the transition to cleaner generating options.

d. **Affordability** —Adequately to Very Well. Although Indiana IOU Electrics' rates have increased in recent years -- due to general inflation, continuing environmental compliance requirements, the need to upgrade or replace aging infrastructure and systems, and fluctuations in fuel costs -- Indiana's electric rates remain competitive both nationally and regionally. For example, in 2023, Indiana ranked 24th out of 50 states in terms of retail electricity prices. https://www.eia.gov/electricity/state/indiana/.

According to EIA's Electric Power Monthly, Indiana's rates are regionally competitive with other similarly situated states in the Midwest region (Illinois, Indiana, Michigan, Ohio, Wisconsin), as well. In fact, as of August 2024, Indiana has the lowest residential rates of the five states and the second lowest industrial rates.
https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a

Indiana's rates are the result of a number of factors – from fuel costs and market prices to infrastructure investment to environmental compliance costs. Significant investment has been made in the state to diversify our generation portfolio, modernize the grid, and support resiliency at the local level. Indiana's energy companies have done this in a managed way that balances the five pillars and ensures we are able to meet the needs of our customers today and tomorrow. The ability to diversify a utility's generation resource mix allows for the mitigation of price volatility and helps balance constraints, such as fuel supplies or supply chains which can impact energy costs. These investments have benefitted the state of Indiana by creating long-term energy cost savings and making us more competitive from an economic development standpoint – hence the record-breaking years announced by the Indiana Economic Development Corporation.

Indiana's current rate-regulation framework has processes in place that facilitate success and ensure affordability for customers. The phase-in base rate adjustment process allows the Indiana IOU Electrics to implement rates over a period of time smoothing rate impacts to customers. Further, each individual utility's fuel adjustment clause (FAC) filing includes the requirements of IC 8-1-2-42(d)(2) and (3), commonly referred to as the "operating expense" and "return" tests, respectively, and IC 8-1-2-42.3. Under the operating expense test, a utility must demonstrate that any increases in fuel costs are not offset by decreases in other non-fuel costs. Under the return test, if the utility's actual return is found to be greater than its authorized return for the most recent 12-month period and the sum of the differentials for the relevant period is greater than zero, then the utility is required to pass back to customers the lesser of the 12-month over earnings or the sum of the differentials for the relevant period. Updates on affordability are also included in the utility's required annual Performance Metrics report (i.e., bill and energy costs trends, disconnection for non-payment, and accounts in arrears). In addition, the TDSIC statute "caps" rate increases from TDSIC tracking mechanisms to 2% annually.

When analyzing affordability, it is important to recognize each utility's unique circumstances including the various stages different utilities and regions are, in the transition to cleaner energy, economic development, as well as how the utilities' capital investments are being sequenced and timed, and whether the state's utilities collect sales or other taxes or charges through electric rates, as these factors can affect cost comparison data.

e. **Environmental Sustainability** — Very well. Indiana utilities have successfully implemented a number of environmental compliance strategies, energy efficiency and demand response programs, expansion of clean energy generation resources, innovative electric vehicle transportation plans, etc. These have resulted in dramatic decreases in air emissions over the years.

f. **Utility cost control** — Very well. Indiana's IOU Electrics consistently and successfully focus on cost control. For example, the Indiana IOU Electrics implement various processes to ensure new generation resources or other projects are competitively bid to promote providing the best value resources/projects to customers. As another example, investments in TDSIC projects are evaluated for costs versus benefits prior to proposing the inclusion of a project in a utility's TDSIC plan. Total operation and maintenance costs are managed and tracked. Annual budgets are established by function with comparison to actuals for management reporting.

As one example, Duke Energy Indiana's 2023 Performance Metrics Report explains that O&M costs (without fuel) per retail customer, are lower than five years ago and comparable to five years ago with fuel, despite inflationary pressures. And Duke Energy's A&G cost per retail customer is lower than it was five years ago.

The Indiana IOU Electrics have experienced both voluntary (resignations and retirements) and involuntary headcount reductions as the labor market changes and evolving business needs change. The Indiana IOU Electrics routinely evaluate workforce plans to ensure staffing with the right skillsets and headcount align with their long-term needs and strategies.

As another example, CenterPoint Energy Indiana South (CEI South) has a continuous improvement team that focuses on reducing and eliminating waste that in turn drives O&M savings. The team executes this strategy through various events such as value stream analyses, Kaizen, structured problem-solving events, and 5S activities.

Each utility conducts robust integrated resource plans; all of which have identified varying levels of generation transition. Integrated Resource Planning is rooted in least cost analysis while taking into consideration risk and uncertainty. The results of these plans have been generation transition activities that provide for long-term O&M savings. When acquiring resources, projects or portions of projects are generally competitively bid to help ensure projects are in-line with markets.

Indiana IOU Electrics utilize innovative pilots to helps identify opportunities to control costs for customers. A recent example is CEI South's securitization of A.B. Brown Power Plant costs.

Most Indiana Electric IOUs have rolled out automated metering infrastructure (AMI), which has driven large O&M reductions throughout the state. As a result of these systems, many utilities have sought and received approval for alternative regulatory plans to remotely disconnect and reconnect customers. This avoids a truck roll, saving customers time and money.

g. **Regulatory efficiency** — Adequately to Very well. Under Ind. Code ch. 8-1-2.5, Alternative Utility Regulation, utilities have the opportunity, under certain circumstances or in unique situations, to file an alternative regulatory plan with the Commission. This provides an avenue for both regulatory flexibility and efficiency in streamlining and standardizing the regulatory process while receiving expedited approvals. Additionally, Indiana's IOU Electrics believe that the Commission and the OUCC perform a high volume of high-quality work given the relatively small sizes of their staffs. However, given the current need to invest in significant infrastructure in short timeframes, there are likely additional opportunities to achieve efficiencies in this area. The Indiana IOU Electrics believe that timelines the Commission and General Assembly have put in place have helped with certain types of cases, but with the continuing complexity of the industry and the increasing need to move quickly with respect to significant anticipated infrastructure needs, regulatory efficiency continues to be an important goal. The Indiana IOU Electrics appreciate the Commission's willingness to work on improving procedural efficiencies in a collaborative manner.

h. **Customer service/connection time** — Very well. The Indiana IOU Electrics strive for customer excellence and track their performance accordingly. Customer service metrics are addressed in the Indiana IOU Electrics' required annual Performance Metrics reports, typically addressing call center operations, service efficiency, customer satisfaction, customer complaints, etc.

i. **Financial health of the utility** — Very well. Indiana has long been viewed as relatively constructive from a financial health perspective. The regulatory frameworks in place including forward looking test years, the TDSIC statute, and riders reasonably provide the ability to recover costs and invest and support utilities' ability to maintain financial integrity. This is demonstrated by Indiana's Investor-Owned Electric Utilities' credit quality. Credit quality is essential to obtaining needed financing at reasonable rates and on reasonable terms, which benefits customers through lower financing costs and lower rates.

For example, as of June 2024, I&M's credit ratings amongst the major credit agencies were:

	Moody's	S&P	Fitch[1]
Senior Unsecured	A3	BBB+	A
Outlook	S	N	S

[1]Affirmed credit rating as of mid-November 2024

As another example, as of October 2024, the major credit rating agencies continued to rate Duke Energy Indiana's securities as follows:

	Moody's	S&P
Senior Secured	Aa3	A
Senior Unsecured	A2	BBB+
Outlook	Stable	Stable

As another example, as of September 2024, the major credit rating agencies continued to rate Southern Indiana Gas and Electric, dba CenterPoint Energy Indiana South as follows:

	Moody's	S&P
Senior Secured	A1	A
Senior Unsecured	A3	BBB+
Outlook	Stable	Stable

As another example: "We continue to assess AES Indiana's business risk as excellent reflecting its rate-regulated utility operations under a constructive regulatory environment. We view AES Indiana's ability to manage regulatory risk as enhanced by credit-supportive regulation under the Indiana Utility Regulatory Commission (IURC), which makes for generally stable cash flows. IPALCO benefits from numerous rate riders, allowing for timely cost recovery of its fuel expenses and the majority of its incremental environmental capital spending. Additionally, the company received approval for its Transmission, Distribution, and Storage System Improvement Charge (TDSIC) plan, which outlines investments of about $1.2 billion and permits the company to earn a tracked return of and on capital spent between 2020 and 2026. Furthermore, Indiana has incentives for clean energy projects that allows projects to be put into rates in between rate cases. We also view the company's ability to settle rate cases as credit supportive. In November 2023, AES Indiana reached a settlement to increase base rates by $71 million. The settlement was approved by the commission in April 2024 with rates effective May 2024." *S&P Global 2024*

Each of the 3 major credit rating agencies point to the stable regulatory environment in Indiana as one of the key credit strengths of our companies. They point to constructive outcomes we've been able to achieve, along with supportive state legislation as evidence. The agencies' views of the regulatory environment is one of the most important considerations they give when assessing us—around 50 percent. Any deterioration in their view of the regulatory environment would have a negative impact on our credit profile and potentially lead to higher borrowing costs for the companies and customers.

j. **Adaptability to the energy transition** (e.g., retirement of coal generation facilities; adoption of distributed energy resources; electrification) — Very well. As mentioned above, Indiana is constructively addressing the expansion of clean energy generation, adoption of DG policies which are fair to both participants and non-participants, and electrification issues (such as electric vehicle transportation plans). Each utility provides the Commission with generation performance metrics within its required annual Performance Metrics report, which may include metrics with regard to a plant's generating capacity and performance, as well as metrics with regard to customer generation (i.e., excess distributed energy, cogeneration, net metering, etc.).

In particular, Indiana's comprehensive and robust IRP process is integral to the State's adaptability to the energy transition. By emphasizing risk and uncertainty, with discussion of "off ramps" should the future turn out differently than expected, Indiana's IRP process produces generation plans that are both reliable and "reasonably least cost". Examples of flexibility by Indiana IOU Electrics include resources with shorter terms, conversion of a coal plant to natural gas or natural gas co-firing, and ratemaking pilots such as the securitization pilot for recovery of retired coal plant costs.

3. 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.

Response:

a. **Reliability** — Yes, with the note that the industry is facing challenges from significant new large loads locating in our service territories (e.g., data centers) and it will take a joint effort among utilities, other parties, and regulators to address infrastructure needed to serve these customer loads on the timetables they are requesting.

b. **Resilience** — Yes.

c. **Stability** — Yes.

d. **Affordability** — Yes.

e. **Environmental Sustainability** — Yes, with the caveats that we must remain mindful of the non-baseload nature of certain renewable resources and we need to continue to allow cost-effective and reliable expansion of clean energy generation.

f. **Utility cost control** — Yes.

g. **Regulatory efficiency** — Generally yes. But see our comments above in response to Question 2(g) and 3(a).

h. **Customer service/connection time** — Yes.

i. **Financial health of the utility** — Yes, assuming Indiana continues to implement constructive regulatory practices.

j. **Adaptability to the energy transition** (e.g., retirement of coal generation facilities; adoption of distributed energy resources; electrification) — Yes, consistent with comments in response to Question 2(j). It is important to recognize that in this area (and other areas), the Commission operates within the policy guidance established by the General Assembly. The General Assembly will continue to play an important role in these areas.

4. Have your organization's customer rates increased at a faster pace than the historical average over the last decade? If so, why?

Response:

Per EIA.gov, Indiana's average retail electric rate was 11.49 cents per kWh in 2023, compared to 9.06 cents per kWh in 2014. In comparison, the national average retail electric rate was 12.68 cents per kWh in 2023, compared to 10.44 cents per kWh in 2014. Also per EIA.gov, Indiana ranked 24th in the nation in rate competitiveness in 2023, up from 35th in 2014. These comparisons indicate that customer rates have generally increased over the past decade, in Indiana and across the United States.

Each Indiana IOU Electric is faced with its own factors based on its own system. However, as stated in response to Question 2(d), in general, rising costs have been due to overall inflation, continuing environmental compliance requirements, the need to upgrade or replace aging infrastructure and systems, and fluctuations in fuel costs. These items, coupled with electricity demand and load increases after years of relatively flat load growth, are contributing to the more recent and anticipated future increase in customer rates as compared to historical rates.

Notably, as shown below, the Indiana IOU Electrics' total retail rate changes have approximated the rate of inflation over the last decade, with realizations varying by class as is customary. (The average realizations are from EEI.)

Indiana Average Realizations

	2014	2023	% Change	Inflation 2014 - 2023	Percent Above/(Below) Inflation	IND AVG CARG	CPI CARG
Residential	$ 0.1118	$ 0.1532	37.0%	28.7%	29%	3.562%	2.844%
Commercial	$ 0.0995	$ 0.1311	31.8%	28.7%	11%	3.112%	2.844%
Industrial	$ 0.0723	$ 0.0846	17.0%	28.7%	-41%	1.761%	2.844%
Total Retail	$ 0.0905	$ 0.1167	29.0%	28.7%	1%	2.865%	2.844%

5. **What could be done to increase cost efficiency?**

   Response:

   Having access to the most competitive resources, as well as receiving expedited approval of certain costs as costs increase over time, would allow for increased cost efficiency. This would also allow utilities to compete for resources that non-regulated entities may be able to transact on more rapidly.

   The Indiana Investor-Owned Electric Utilities continue to focus on cost control and efficiency. Some examples of this focus include the evaluation of affordability within its Integrated Resource Planning process in the selection of a preferred portfolio, evaluation of its workforce strategy including use of contractors and outsourcing, and competitively bidding procurement activities when appropriate. See also actions noted in response to 2(f) above.

6. **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?**

   Response:

   The Indiana Investor-Owned Electric Utilities have experienced capital building cycles, stemming from the need to comply with new environmental compliance requirements, the need to replace aging infrastructure, the expansion of clean energy generation, grid modernization, and load growth primarily driven by hyperscale customers. Currently, replacement of retiring plants, public policy, electrification, and change in customer needs, as well as economic development and its resulting significant current and anticipated load growth (which includes the need to address transmission and distribution size and the need for automation and built-in intelligence), is driving a build cycle across the industry. Our companies anticipate needing to make substantial capital investments over the next few years to meet our customers' demand and energy requirements.

For example, I&M is in the midst of a significant capital building cycle to accommodate increased load and estimates capital expenditures (excluding AFUDC) of approximately $7.332 billion for the 2025 through 2029 period.

As another example, Duke Energy Indiana estimates capital expenditures of $6.475 billion for the time period of 2024 through 2028 (per the Duke Energy 2023 earnings review update to investors).

NIPSCO Electric is in a high growth phase of its capital building cycle, given the transition to cleaner energy, a growing customer base, a transformation in customer care, metering and billing functions, as well as the need to keep up with emerging customer communication technologies. Repairs, maintenance, and replacements due to aging infrastructure, along with cost increases due to inflation, add to this high growth capital phase.

Multi-Year Rate Plans & Performance Incentive Mechanisms:

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

   Response:

   Indiana's Investor-Owned Electric Utilities have filed the following electric base rate cases since 2000:

   AES Indiana: AES Indiana has filed 3 base rate cases since 2000 – in Cause No. 44576, filed on December 29, 2014; Cause No. 45029, filed on December 21, 2017; Cause No. 45911, filed on June 28, 2023.

   CenterPoint Energy: CenterPoint Energy Indiana South has filed 3 base rate cases since 2000 – in Cause No. 43111 filed on September 1, 2006, in Cause No. 43839 filed on December 11, 2009, and Cause No. 45990 filed on December 5, 2023. CEI South is required to file its next base rate case no later than 12/31/2028, as required by the TDSIC statute (when CEI South's 2024-2028 TDSIC plan expires).

   Duke Energy Indiana: Duke Energy Indiana has filed 3 base rate cases since 2002 -- Cause No. 42359, filed 12/30/2002; Cause No. 45253, filed 07/02/2019; and Cause No. 46038, filed 04/04/2024.

Indiana Michigan Power Company: I&M has filed 6 base rate cases since 2000 -- 2007 (Cause No. 43306); 2011 (Cause No. 44075); 2017 (Cause No. 44967); 2019 (Cause No. 45235); 2021 (Cause No. 45576); and 2023 (Cause No. 45933). I&M expects to continue to file base rate cases as needed in order for it to meet its customers' needs for service, while maintaining affordable rates, through replacement of aging infrastructure, distribution and information technology systems modernization, and enhanced reliability and resiliency of the grid, as well as to maintain safe and reliable generation resources. Additionally, with the significant changes I&M is currently facing in regard to new generation acquisition, changes in the generation portfolio, the need for increased investment in transmission and distribution due to aging infrastructure, and large load customers locating in Indiana, I&M expects to continue to make base rate case filings as needed.

Northern Indiana Public Service Company: NIPSCO has filed 6 base rate cases since 2000 -- 2008 (Cause No. 43526 – rates not implemented); 2010 (Cause No. 43969); 2015 (Cause No. 44688); 2018 (Cause No. 45159); 2022 (Cause No. 45772); 2024 (Cause No. 46120).

Given the need for infrastructure to meet customer load requirements, the Investor-Owned Electric Utilities generally anticipate filing base rate cases more frequently than in the past.

2. **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. Need to emphasize unexpected load growth, investments**.

Response:

Yes, the Indiana IOU Electrics would support that as a voluntary option, particularly if the option included a limited revenue cap option, a limited price cap option, *and* a formula rate option. We believe flexibility and optionality is important, particularly in light of the changing load forecasts and resulting capital investment needs we are experiencing.

If MYRPs become an option in Indiana, we recommend starting out with a shorter time frame, such as three years, with guardrails and off-ramps as appropriate. A limited scope may be advisable, as well.

3. **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?**

Response:

Generally, yes, as noted below.

I&M currently conducts a seven-year forecast/outlook at the FERC account level.

Duke Energy Indiana notes that MYRP forecasts are possible at the FERC account level, but would require the use of assumptions and informed allocations in order to expand the forecast for ratemaking purposes, particularly for FERC plant accounts.

CenterPoint notes that it is able to forecast at the FERC account level for a future test year.

NIPSCO would have to make modifications to its planning process to develop FERC account level forecasts if required for a MYRP. Forecasting cost of service at the FERC account level is a requirement today in rate cases which NIPSCO complies with. NIPSCO does not perform financial planning at a FERC account level today and performs an allocation of the future test year based upon FERC allocations from the historical base period.

AES Indiana notes that it is able to forecast at the FERC account level for a future test year beginning in 2025.

4. **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?**

Response:

Given the expected capital needs we are facing in the near-term, no. The expansion of clean energy generation, including expansive new generation acquisition and changes in generation portfolios, as well as the need for increased investment in transmission and distribution due to aging infrastructure, the need to meet substantially increasing load requirements, and to avoid "reopeners" within a MYRP, makes the price cap methodology described above problematic from a capital recovery and financial integrity perspective. Indiana's Investor-Owned Electric Utilities have an obligation to serve and should have the ability to recover its costs plus a reasonable rate of return. There are also other numerous drawbacks from instituting price or revenue caps, including a disincentive for investment, which may impact innovative solutions needed in a large new load paradigm, as well as potentially unintended impacts to service quality or utility financial integrity.

Moreover, inflation and productivity factors used in price cap regulation may not accurately reflect the utility's actual cost trajectory – especially in a high-capital industry subject to fluctuations in labor, materials, and energy costs. This limits the utility's ability to recover unforeseen expenses or cost changes due to regulatory, environmental, or economic shifts. In addition, a pure price cap does not take utility load and consumption into consideration. This would be exacerbated year by year, unless there is a mechanism to adjust or true up the volumes based on actual consumption from year to year.

In addition, price caps may not align with regulatory or operational goals. For example, if a utility operated in a price cap environment and needed to make grid resilience or clean energy investments, the price cap constraint may harm the utility's financial integrity or result in deferral of needed investments.

Price caps also do not provide mechanisms to address evolving needs – such as DERs, EVs, other new technologies, cybersecurity, and shifts in customer loads and resource mixes.

Dependence on historical productivity will be problematic if past trends do not reflect current or future productivity trends. Technology advances or other unique circumstances may render historical productivity studies inaccurate for future projections.

Lastly, price caps may discourage innovation, by limiting the incentive to implement transformative initiatives. Cost of service regulation, on the other hand, can adapt to innovation provided the utility supports the prudence and reasonableness of its investments.

5. **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 revenue requirement 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?**

   Response:

   Not all Electric IOUs have the same riders or recover costs the same way (i.e., base rates vs. riders), with each having its own business model and unique circumstances, objectives, and regulatory risks. This scenario may be somewhat more feasible than a pure price cap, depending upon what capital and expense trackers are included. It is possible that Indiana utilities could utilize an optional process to stay out of base rate cases for three to five years, if all existing capital and expense trackers remain in place. However, as stated previously, one size will not fit all utilities; flexibility and optionality are necessary aspects of such a regulatory structure, as are guardrails and off-ramps.

   Notably, while a "limited price cap" would be an improvement over a "pure price cap", a limited price cap would still have some of the same drawbacks as the pure price cap, only to a lesser extent. Similarly, a limited price cap may still see the same issues with respect to volume forecasts as a pure price cap. Also, the lengthier the term, the riskier the plan is likely to be.

   Moreover, a five-year term under a formula-based price cap regime would still introduce a disconnect between a utility's actual costs and the price cap utility revenues. Additionally, a price cap would disincentivize utility energy efficiency because it would reduce revenues without necessarily reducing costs.

6. **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?**

   Response:

   Given the expected capital needs we are facing in the near-term, no. The expansion of clean energy generation and the need to meet substantially increasing load requirements makes the price cap methodology described above problematic from a capital recovery and financial integrity perspective. Indiana's IOU Electrics have an obligation to serve their customers and must have the ability to recover their costs plus a reasonable return on capital invested in the business. A "pure revenue cap" presents similar flaws and risks as does a "pure price cap".

7. **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? Keep all existing trackers …. Clarify price vs revenue caps.**

   Response:

   This scenario would be more feasible and preferable than the other options identified, depending upon what capital and expense trackers are included. It is possible that Indiana utilities could utilize such an optional process to stay out of base rate cases for five years, if all existing capital and expense trackers remain in place. However, as also stated previously, one size will not fit all utilities as each utility has different riders or ways of recovering costs, as well as their own business model and unique circumstances for its system, objectives, and regulatory risks. Therefore, flexibility and optionality are needed aspects of such a regulatory structure.

   In addition, we believe options such as formula rates should be included in a MYRP scenario. Formula rates could be trued up annually to assure that customers pay for the actual costs of serving them, no more and no less.

   Indiana's regulatory construct, developed over decades of experience, works relatively well and should not be discarded. However, an optional limited revenue cap or formula rate mechanism used in conjunction with existing rate adjustment mechanisms could work to improve regulatory and administrative efficiency without creating undue harm and risk.

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

Response:

It is unclear what is meant by “financial benefits.” However, it is possible that a voluntary and flexible MYRP regulatory structure (such as a limited revenue cap or a formula rate) could allow Indiana utilities to maintain financial integrity and credit quality, depending on the breadth of capital and expense trackers that would remain in place. It is important to keep in mind that new regulatory structures such as MYRPs introduce additional risk for utilities, in addition to potential benefits, and therefore sufficient guardrails would be a necessary component of any MYRP structure. It is also necessary to keep in mind that cost recovery is very important to debt and equity investors. If the MYRP can achieve cost recovery plus rate and/or revenue predictability to both customers and the utility, a MYRP option could be a valuable addition to Indiana’s regulatory toolbox.

A cost-of-service regulatory regime such as exists in Indiana generally achieves goals of adequate and reliable service, reasonable rates, and financial integrity, while also taking into consideration individual utility circumstances and customer needs. A multi-year cost of service plan (such as a formula rate) with incentives for each utility’s selected performance incentives could provide Indiana utilities an opportunity to target their unique areas of performance focus and achieve price and service quality goals that consider each utility’s unique circumstances while still providing an opportunity to plan and invest capital and O&M for a longer than one year planning period.

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

Response:

In terms of increasing predictability of bills, probably yes. But any price or revenue cap (or formula rate) must also allow for cost recovery and maintenance of financial integrity, while supporting needed investment and innovation— if not, customers will be harmed in the long run by higher financing costs.

In addition to including capital expense trackers, a MYRP should also include guardrails, “reopeners” to adjust the plan or “off ramps” to leave the plan when unexpected changes or results are encountered. For example, Hawaii allows the utility to request to initiate a re-opener or “off-ramp” mechanism, subject to explicit triggering events related to the utility’s credit rating and actual return on equity. *See In the Matter of Public Utilities Commission Instituting a Proceeding to Investigate Performance-Based Regulation*, Docket No. 2018-0088, Decision and Order No. 37507 (Hawaii PUC; 12/23/2020).

Both price caps and revenue caps offer some benefits to customers by increasing rate and/or bill predictability. For example, price caps based on an inflation index could offer customer predictability about price changes. However, the Indiana IOU Electrics believe a multi-year cost of service plan can achieve the same goals without the downsides of a price or revenue cap. A customized multi-year cost of service regime can set rates and provide customers predictability about rates while keeping utilities' unique circumstances, issues and areas needing focus and prioritization in mind.

10. **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 optional (opt-in) or if the PIMs are set specifically for each utility rather than the same PIM target for all utilities?**

Response:

Similar to a MYRP, Indiana Investor-Owned Electric Utilities do not currently see a compelling need to adopt PIMs given the current regulatory construct in Indiana and the opportunity the Commission and stakeholders have to access utility performance as part of ongoing regulatory proceedings. It is important to recognize that many Indiana Investor-Owned Electric Utilities already report to, and collaborate with, the Commission on the utility's performance in several targeted areas over a ten-year period within the utility's annual performance metrics report. This report allows the Commission and other stakeholders to review, scrutinize, and hold the utility accountable in its performance in targeted areas.

As mentioned above, we believe optionality is key, as are utility-specific PIMs. Given the differing utility service territories, customer composition, utility sizes, etc., having the same PIM targets for all utilities does not make sense. In addition, we would caution that PIMs need to be carefully designed, clearly defined, reasonably attainable, readily quantifiable using available data, reasonably objective and largely independent of factors beyond a utility's control, and easily interpreted and independently verifiable.

11. How would you define success or failure for a performance-based regulation mechanism such as a MYRP or PIM?

Response:

Maintenance of financial integrity; ability to make necessary investments when needed; increased predictability of rates and revenues; increases in incentivized performance; increases in efficiency and performance improvements; achievement of state policy goals.

12. 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?

Response:

Indiana Investor-Owned Electric Utilities do not currently see a need to adopt a mandatory MYRP given the current regulatory options available in Indiana. A MYRP should not be required, but rather it could be an option. The current system is workable and relatively constructive for customers and utilities. However, we recognize that improvements can still be made. As long as new regulatory structures recognize that: one size will not fit all utilities (as each utility has different business models, objectives, and regulatory risks), flexibility and optionality are indispensable, and cost recovery and financial integrity are critical, MYRPs may be a useful option. As far as incremental improvements, we believe strategies to facilitate construction and acquisition of resources to meet the needs of new large customer loads and to facilitate the expansion of clean energy generation are currently needed.

In general, we believe incremental updates to Indiana's existing regulatory structure would be a more effective and appropriate approach. Utilities operate within unique circumstances and a one size fits all or a blanket approach towards a PBR, a MYRP or PIMs may not work most effectively for each utility. The decision on a PBR regime, its timing, length (duration/term) and features are best left to the individual utilities who can opt in for any of the features, their timing and duration.

<u>**Additional Information:**</u>

1. **Do you have any additional information or comments to share regarding the exploration of performance-based regulation for Indiana utilities?**

   Response:

   It would be helpful to see information on the results of MYRPs and PIMs that have been in place in other states – whether they have been viewed as a success or not, and whether there were any unintended consequences.

2. **Would you find value in a second workshop? If so, what topic areas would you want to discuss?**

   Response:

   Yes. A second workshop and further discussion with utilities to include their ongoing feedback would be beneficial and the Indiana IOU Electrics would be open to such interactions. In particular, it might be helpful to have an opportunity to explore the ways that PBR can work in concert with utilities needing to make ongoing capital improvements that may not be reflected in an historical average. Also, it may be helpful to have an opportunity to discuss the guardrails and potential off-ramps or re-openers that would be necessary in the event of significant economic or policy change.

In addition, an additional workshop that provides the Indiana Investor-Owned Electric Utilities with a summary/overview of Christensen's draft report and an opportunity to comment before it presents its findings to the General Assembly in the Fall of 2025 would be valued.