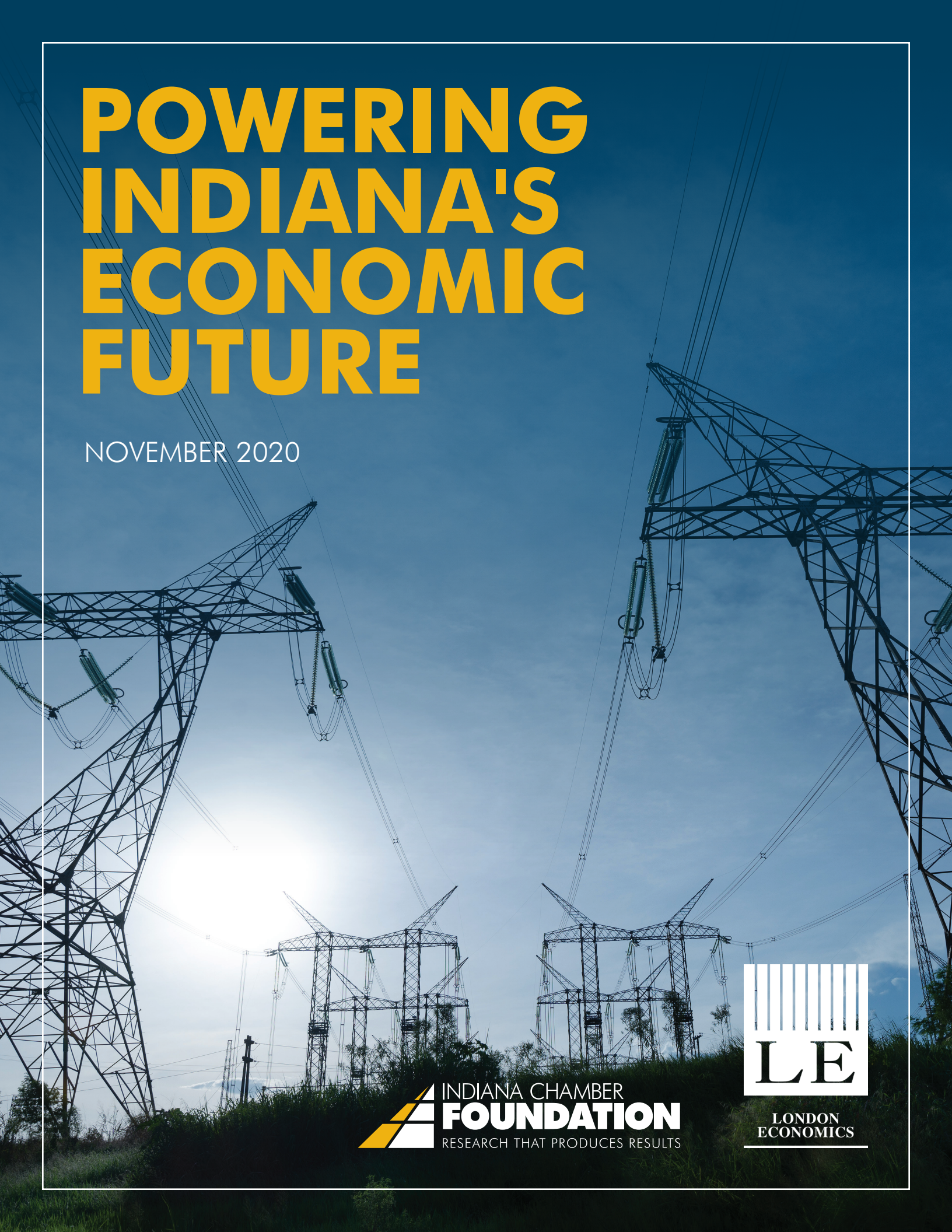
POWERING INDIANA'S ECONOMIC FUTURE

NOVEMBER 2020



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**The Indiana Chamber of Commerce Foundation commissioned London Economics International LLC (LEI) to conduct an objective energy study with input from the Indiana Chamber of Commerce and the Advisory Council. The conclusions and recommendations in the study do not necessarily reflect the views of all the Advisory Council members.*

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Indiana Energy Policy Study

prepared for the Indiana Chamber of Commerce Foundation ("ICCF") by London Economics International LLC

November 10th, 2020

LONDON ECONOMICS

London Economics International ("LEI") was retained by the Indiana Chamber of Commerce Foundation ("ICCF") to perform a study on Indiana's Energy Policy ("the Study"). The Study is intended to contribute to a deeper understanding of the factors driving energy changes, and to aid in the process by providing a solid foundation to assist policymakers, consumers, and other stakeholders in: understanding how the industry and its regulation works; how things have changed; and how things could develop going forward. Finally, the Study explores options to address identified issues, and the avenues available to make such changes. Based on a thorough assessment of Indiana's energy sector, LEI believes the State should adopt a set of principles and activities to direct future policy. These include:

- ***creating a clearly defined objective function;***
- ***maintaining a technology and ownership neutral approach;***
- ***avoiding funding public policy goals through electricity rates;***
- ***acknowledging the importance of optionality;***
- ***learning from other jurisdictions;***
- ***recognizing that distributed energy resources will provide a form of competition;***
- ***reviewing definitions of reliability and how much consumers are willing to pay for it;***
- ***performing a detailed review of rate design; and***
- ***avoiding any sudden policy movements.***

Table of contents

Table of figures

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List of acronyms

A/S	Ancillary Services
ACE	Affordable Clean Energy
ACS	American Community Survey
AEO	Annual Energy Outlook
AEP	American Electric Power
AMI	Advanced Meter Infrastructure
AML&P	Anderson Municipal Light and Power
AMR	Automatic Meter Reading
APT	Arbitrage Pricing Theory
ASHARE	American Society of Heating, Refrigerating and Air-Conditioning Engineers
ATRR	Annual Transmission Revenue Requirement
AUR	Alternative Utility Regulation
BRP	Baseline Reliability Projects
BTM	Behind-the-Meter
BTU	British Thermal Units
C&I	Commercial and Industrial
CAGR	Compound Annual Growth Rate
CAIDI	Customer Average Interruption Duration Index
capex	Capital Expenditures
CAPM	Capital Asset Pricing Model
CC	Combined-cycle
CCA	Community Choice Aggregation
CCOS	Class Cost of Service
CCRs	Coal Combustion Residuals
CCS	Carbon Capture and Storage
CCUS	Carbon Capture, Utilization, and Storage
CELRL	Corps of Engineers Great Lakes and Ohio River Louisville District
CEO	Chief Executive Officer
CES	Clean Energy Standard
CHOICE	Comprehensive Hoosier Option to Incentivize Cleaner Energy
CHP	Combined Heat and Power
CIP	Capital Improvement Plans
CLCPA	Climate Leadership and Community Protection Act
CO2e	CO2 equivalents
Cook	Donald C. Cook Nuclear Plant
Co-Ops	Cooperative Utilities
COS	Cost of Service
CPS	Clean Energy Portfolio Standard
CREZ	Competitive Renewable Energy Zones
CSAPR	Cross State Air Pollution Rule
CT	Combustion Turbine
DERs	Distributed Energy Resources
DSC	Debt Service Coverage
DSM	Demand-Side Management
Duke	Duke Energy Indiana, LLC
E85	Flex Fuel
EE	Energy Efficiency
EERS	Energy Efficiency Resource Standard
EGS	Electric Generation Supplier
ELG	Effluent Guidelines
ERCOT	Electric Reliability Council of Texas
ERI	Environmental Resilience Institute
ESG	Environmental, Social, and Governance
ESM	Earning Sharing Mechanisms
EVs	Electric Vehicles
FERC	Federal Energy Regulatory Commission
FIT	Feed-In Tariff
FPL	Federal Poverty Level
FSC	Fisher, Sheehan & Colton
G&T	Generation and Transmission
GHG	Greenhouse Gas
GHI	Global Horizontal Irradiance
GIPs	Generation Interconnection Projects
GPI	Great Plains Institute
GSP	Gross State Product
GWh	Gigawatt hour

HEAG	Home Energy Affordability Gap
HERS	Home Energy Rating Systems
HGL	Hydrocarbon Gas Liquids
HVAC	Heating, Ventilation and Air Conditioning
I&M	Indiana Michigan Power Company
ICCF	Indiana Chamber of Commerce Foundation
IDEM	Indiana Department of Environmental Management
IEA	Indiana Energy Association
IEC	Indiana Electric Cooperatives
IGWS	Indiana Geological and Water Survey
I&M Transco	AEP Indiana Michigan Transmission Company
IMM	Independent Market Monitor
IMPA	Indiana Municipal Power Agency
INDIEC	Indiana Industrial Energy Consumers, Inc.
IOU	Investor Owned Utilities
IPL	Indianapolis Power & Light Company
IPP	Independent Power Producers
IRC	Indiana Residential Code
IRP	Integrated Resource Plan
ISO	Independent System Operator
ITC	Investment Tax Credit
IURC	Indiana Utility Regulatory Commission
JTS	Joint Transmission System
kW	kilowatt
kWh	kilowatt-hour
LBNL	Lawrence Berkeley National Laboratory
LCA	Life Cycle Assessment
LCOEs	Levelized Costs of Electricity
LCOP	Levelized Cost of Pipeline
LEI	London Economics International LLC
Li-ion	Lithium-ion
MAGI	Modified Adjusted Gross Income
MAP	Maximum Achievable Potential
MATS	Mercury and Air Toxics Standards
MMcf	Million Cubic Feet
MEPs	Market Efficiency Projects
MGT	Midwestern Gas Transmission
MISO	Midcontinent Independent System Operator
MIT	Massachusetts Institute of Technology
MPSC	Michigan Public Service Commission
MTEP	MISO Transmission Expansion Plan
Munis	Municipally-owned utilities
MVPs	Multi-Value Projects
MW	Megawatts
MWh	Megawatt hour
NASEO	National Association of State Energy Officials
NERC	North American Electric Reliability Corporation
NIPSCO	Northern Indiana Public Service Company
NMA	National Mining Association
NPD	Non-Powered Dams
NSI	Net Scheduled Interchange
NWA	Non-wires Alternative
NYSERDA	New York State Energy Research and Development Authority
O&M	Operation and Maintenance
OED	Office of Energy Development
OMS	Organization of MISO States
OPSI	Organization of PJM States Inc.
OUCC	Office of Utility Consumer Counselor
OVH	Ohio Valley Hub Pipeline
PBR	Performance-based Ratemaking
PIM	Performance Incentive Mechanism
PPA	Power Purchase Agreement
PRA	Planning Resource Auction
PTC	Production Tax Credit
PUCO	Public Utilities Commission of Ohio
PV	Photovoltaic
RAB	Regulated Asset Base
RAP	Realistic Achievable Potential
RCTM	Regional Capacity Trading Market
RECs	Renewable Energy Credits

REMC	Rural Electric Membership Corporation
REV	Reforming the Energy Vision
RFPs	Requests for Proposals
RGGI	Regional Greenhouse Gas Initiative
ROE	Return on Equity
RP&L	Richmond Power and Light
RPM	Reliability Pricing Model
RPS	Renewable Portfolio Standard
RTEP	Regional Transmission Expansion Plan
RTOs	Regional Transmission Organizations
RUS	Rural Utility Service
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SMRs	Small Modular Reactors
SPV	Special Purpose Vehicle
SUFG	State Utility Forecasting Group
T&D	Transmission and Distribution
TDSIC	Transmission, Distribution, and Storage System Improvement Charge
TIER	Times Interest Earned Ratio
TWh	Terawatt hour
US	United States
US DOE	US Department of Energy
US EIA	US Energy Information Administration
US EPA	US Environmental Protection Agency
WACC	Weighted Average Cost of Capital
WVPA	Wabash Valley Power Association
YTM	Yield to Maturity

1 Executive summary

The Indiana Chamber of Commerce Foundation ("ICCF") engaged London Economics International LLC ("LEI") in June 2020 to conduct a study on energy policy ("the Study") in Indiana, which aims to review "Indiana's energy needs, production, consumption, pricing, economic impacts, public policy options, and regulatory systems."[1, 2] Specifically, the Study intends to:

- offer a solid foundation to assist policymakers, consumers, and other stakeholders in understanding how the industry and its regulation works. These topics are covered in Sections 4 through 6;
- provide an understanding of how things have changed. A notable component here relates to rising energy costs, although other issues to be addressed include the energy mix, reliability, and regulatory considerations (to name a few). This is covered in Section 7 and the beginning part of Section 8;
- provide reliable information on how things could develop going forward. Again, an important component here relates to costs, but it is not the only area of concern. This is covered in the latter part of Section 8, as well as Section 9; and
- identify options that are available to address issues discovered in the Study (e.g., lower costs or reduce growth rate trajectory of costs, enhance reliability), determine the avenues available to make such changes (e.g., legislative process, regulator), and suggest a list of recommendations most useful to all stakeholders and policymakers. These topics are considered in Sections 10 and 11, with concluding remarks and recommendations explored in Section 12.

To achieve these goals, LEI has prepared this comprehensive report to provide a deeper understanding of the factors driving energy changes in Indiana and the region. The report covers the following topics, as shown in Figure 1: an overview of Indiana's energy resources, electricity industry, and regulatory framework; a comparison of the State's national and regional ranking for electricity costs, affordability, and reliability; a discussion of the factors that have driven and will continue to drive cost changes in Indiana and the region; a review of other considerations and concerns; a discussion of what can be done through the legislative process; and an overview of the goals of various stakeholders.

Throughout the Study, LEI has compared Indiana's energy sector relative to other states in the region. For the purposes of this Study, "region" is defined as the following neighboring states: Illinois, Kentucky, Michigan, and Ohio. These states were selected due to their proximity to Indiana, as well as their similarities with the State.

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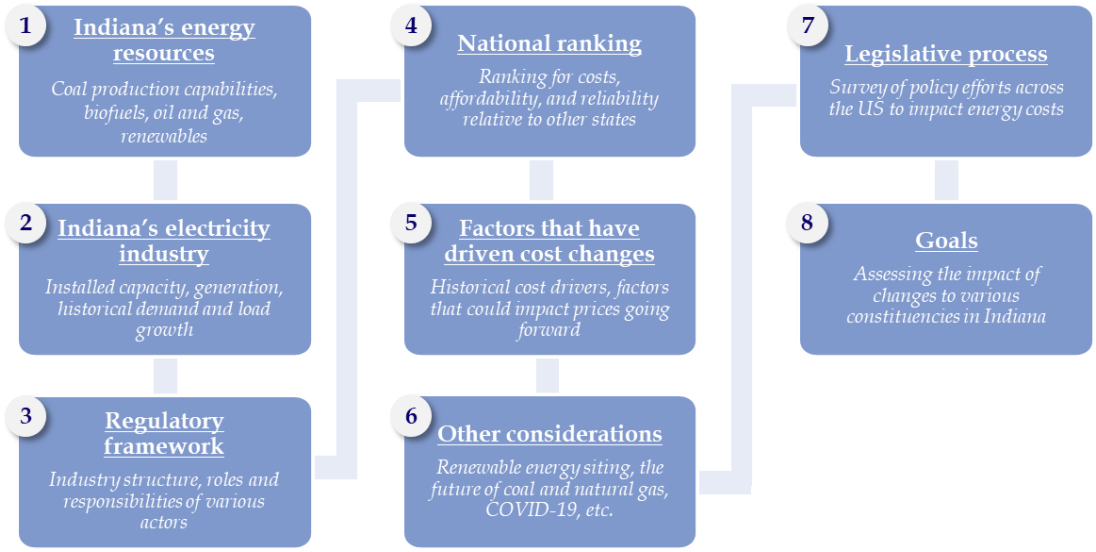
[1] Contract between ICCF and LEI signed on June 12, 2020.

[2] ICCF. *Request for Proposals: Indiana Energy Policy Study.* April 1, 2020. p. 1.

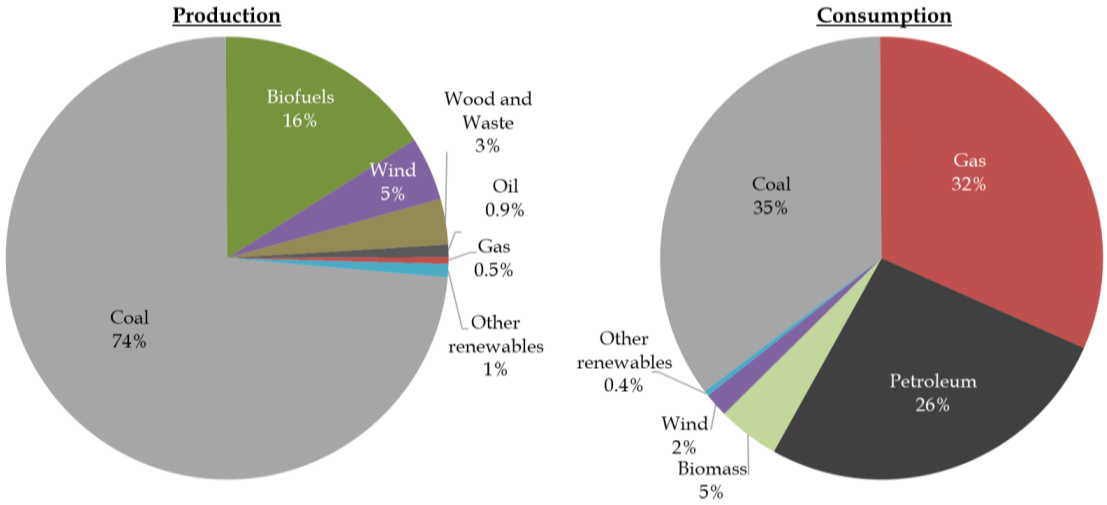
Figure 1. Issues examined in the Study



1.1 Indiana's energy resources

Indiana, with a population of 6.76 million, produces and consumes a wide range of energy, including fossil fuels and renewable resources. Considering all fuels and uses, in total, Indiana is a net importer. Fossil fuels include coal, oil, and natural gas, while renewable resources include biomass products such as biofuels and wood and waste energy, as well as wind, solar, hydroelectric, and geothermal. Figure 2 presents a visual representation of Indiana's production and consumption of energy by source for 2018 using EIA data, excluding imports to the State.

Figure 2. Indiana's energy production and consumption by primary source (2018) – illustrative



Note: EIA data is based on in-state resources, so nuclear energy imported from Michigan is not included in either chart. Additionally, data is standardized and presented in British thermal units. Therefore, this figure is presented as illustrative.

Source: Based on information from the EIA's State Energy Data System. Final data for 2019 to be released on June 25, 2021.

The current state and future potential for these energy resources in Indiana is discussed briefly below, with further details provided in Section 4:

- **coal** has historically been Indiana's dominant energy resource in terms of reserves, production, and consumption, although coal's production and consumption has declined over the past decade. Indiana ranked 7th nationally in terms of coal production in 2019, and this downward trend is expected to continue;
- while production and proven reserves of **oil and gas** are comparatively much lower than coal, oil and gas are still important resources on the consumption side, with natural gas, in particular, growing in usage over the past decade;
- **biofuels**, notably fuel ethanol, are an essential foundation of Indiana's renewable and total energy production base. Biofuels are one energy resource where Indiana's in-state production exceeds its in-state consumption. Indiana ranked 5th nationally in the production of both ethanol and biodiesel in 2018;
- **renewable energy resources** have grown in usage over the past decade and are expected to continue growing in usage going forward. This is particularly true for wind and solar, primarily due to technological improvements, declining costs, and various government and other incentive programs. Storage is also being developed in Indiana to help balance intermittent resources. However, there is limited potential for other renewable resource development such as **hydro, geothermal, and wood and waste biomass**;
- **nuclear** plays an essential role in Indiana's overall electricity supply mix (making up around 10% of Indiana's electricity consumption in 2019), although no nuclear plants are located in the State. Nuclear generation stems from Indiana Michigan Power ("I&M")'s Cook nuclear plant (2.2 GW), located in Michigan, which dedicates 65% of its output to I&M retail customers in Indiana. Based on recent data, Units 1 and 2 will continue their operations until 2034 and 2037, respectively. New conventional nuclear build appears to be uneconomic; going forward, small modular reactors ("SMRs") are viewed by some as a next wave, but it is not clear whether their promise will be realized; and
- **cogeneration** systems are an important resource primarily for industrial customers in Indiana, as they provide an efficient means of generating on-site power while recovering thermal energy for use in industrial processes. These systems total 2,418 MW of capacity in the State and are used mostly in primary metals and petroleum refining applications.

1.2 Indiana's electricity industry

Indiana's electricity sector is regulated and is served by vertically integrated utilities and several independent power producers ("IPPs"). An overview of the State's electric industry structure is illustrated in Figure 3. In Indiana, electric utilities fall into three categories:

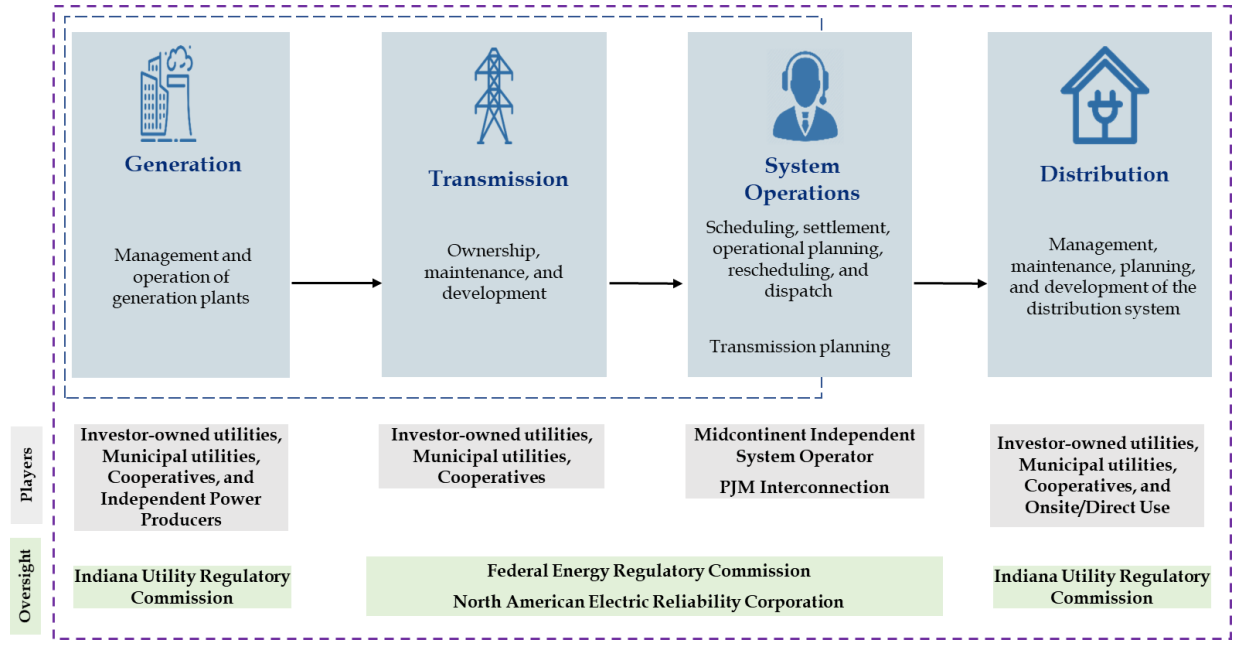
(i) investor-owned utilities ("IOUs");

(ii) municipal utilities ("munis"); and

(iii) rural electric membership cooperatives ("REMCs" or "co-ops").

These utilities differ in terms of their business models, governance and oversight structures, and profit motivations. IOUs are owned by shareholders and, naturally, are profit-oriented. In contrast, co-ops are owned by their members, and munis, by the host municipality, and so are typically not profit-oriented.

Figure 3. Electric industry structure in Indiana



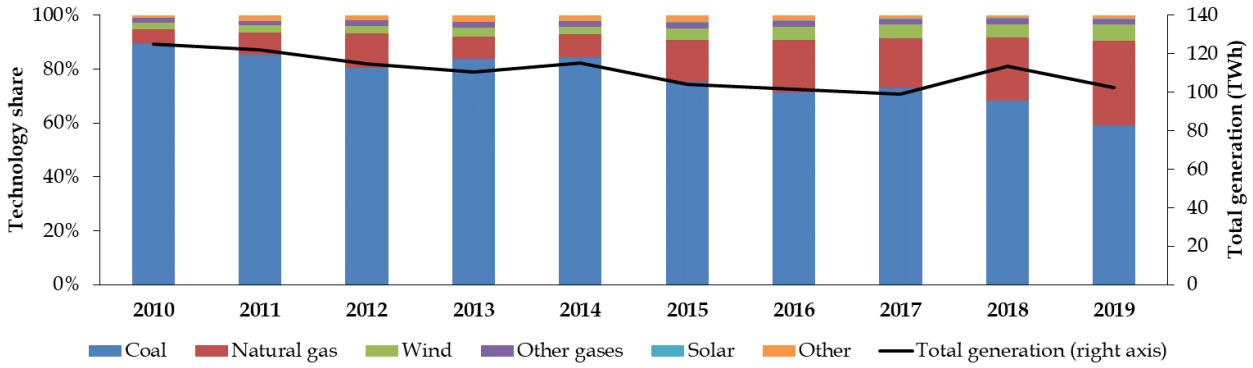
Note: All Indiana cooperatives and most munis are self-regulating, thus, are not under the IURC.

IOUs, Wabash Valley Power Association, Hoosier Energy, and munis own and maintain the transmission lines in the State. However, either the Midcontinent Independent System Operator ("MISO") or the PJM Interconnection ("PJM") coordinates the flows on these transmission lines. Meanwhile, IOUs, REMCs, and munis own, operate, and maintain the distribution assets within their exclusive service territory.

The State's in-state **generation mix** is dominated by coal (59% as of 2019), followed by natural gas (31%), and wind (6%) resources. Indiana's resource mix has evolved significantly over the past decade, with coal's share of generation decreasing from 90% in 2010. Meanwhile, natural gas and wind generation have increased over the same period—up from 5% and 2% of generation in 2010, respectively. Figure 4 demonstrates this evolution in the State's generation mix over the 2010-2019 period.

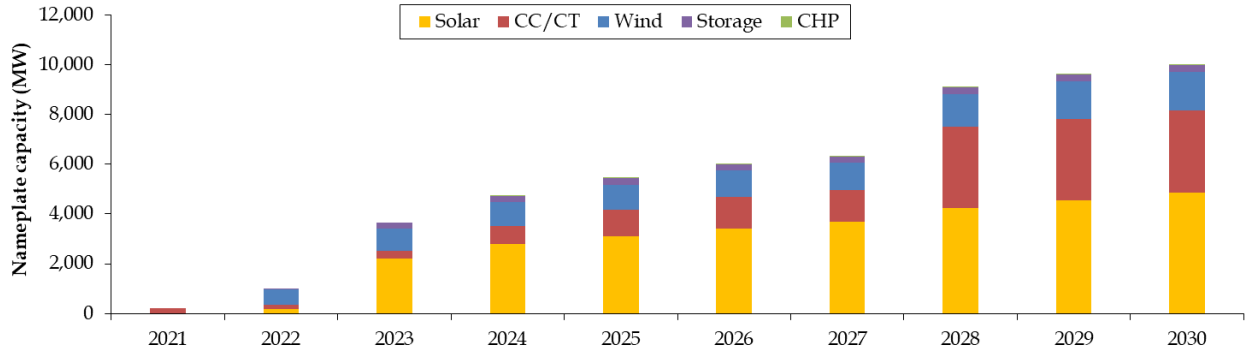
In terms of **planned retirements and additions**, as much as 7.7 GW of coal is set to retire by 2028 (29% of 2019 total installed summer capacity for all resources), based on the most recent integrated resource plans ("IRPs") filed by Indiana's regulated utilities. This will be replaced primarily by anticipated additions in natural gas, solar, and wind-powered generation (3.3 GW, 4.8 GW, and 1.6 GW by 2030, respectively), which are illustrated in Figure 5.

Figure 4. In-state electric generation in Indiana (2010-2019)



Source: US EIA. *Net Generation by State by Type of Producer by Energy Source.* 2020.

Figure 5. Cumulative planned resource additions, 2021-2030



Note: Includes I&M's preferred portfolio, which incorporates additions in both Indiana and Michigan. Natural gas additions are represented by the CC/CT bar (combined-cycle ("CC") gas plant/combustion turbine ("CT")). CHP refers to combined heat and power systems.

Sources: IURC. *2020 Report to the 21st Century Energy Policy Development Task Force.* August 14, 2020; various utility IRPs.

Notably, the additions to renewable generation in Indiana are occurring amidst less aggressive **clean energy policies** in the State. For instance, the Comprehensive Hoosier Option to Incentivize Cleaner Energy ("CHOICE") program, Indiana's voluntary clean energy program, was adopted in 2011. While it targets voluntary procurement of 10% of electricity (relative to 2010 retail sales) from clean energy sources by 2025, there has been no utility participation in the program to date.

Nevertheless, Indiana generated 6% of 2010 electricity sales from renewables (wind, solar, hydro) in 2019. This suggests that State- and Federal-level government action is not the only means through which greater renewables deployment can be encouraged, and that this has occurred in large part through improving project economics. A review of other clean energy policies in the State, as well as further details pertaining to Indiana's electricity industry, are covered in Section 5.

1.3 Regulatory framework

The Indiana Utility Regulatory Commission ("IURC") governs IOUs and some munis. The IURC is governed by its legislative mandate to balance the interests of utilities with the interests of the customers they serve. The goal is to ensure "just and reasonable" rates consistent with service and reliability expectations. The Commission governs IOUs, and nine munis only in terms of setting rates and charges; REMCs set their rates and charges through their Boards, opting out of the IURC's jurisdiction. Electric rates in Indiana are determined through the traditional cost of service ("COS") approach with several pass-through charges.

Indiana passed the Alternative Utility Regulation ("AUR") Act in 1995. Under this law, an energy utility can choose to adopt alternative regulatory mechanisms and establish rates and charges based on market or average prices, price caps, index based prices, and prices that use performance-based rewards or penalties (either related or unrelated to its return or property), which are designed to promote efficiency in providing retail energy services.[3] Rates and charges are to be in the public interest and enhance or maintain the value of the utility's retail energy service or properties.[4] Any energy utility that plans on adopting an alternative regulation should submit an alternative plan to the Commission. The Commission will review and approve, deny, or revise the plan. The energy utility may accept or reject the Commission's Order modifying the proposed plan. An energy utility may also withdraw a proposed plan prior to the Commission's approval.[5]

Indiana's ratemaking process for electric and gas utilities is similar to what is being used in many US jurisdictions; the process begins with a utility filing an application with the Commission to request for changes to its rates and/or terms of service. The process—which can either be fully litigated or settled—usually takes a year to complete. Further information regarding the ratemaking process is discussed in Section 6.

1.4 Indiana's national and regional ranking

Over the last ten years, Indiana's national ranking for electricity prices across all customer classes has worsened significantly. As illustrated in Figure 6, the decline has been most substantial for commercial customers, with electricity prices falling from 18th best in the country in 2010 to 37th by 2019, followed by industrial (16th to 32nd) and residential customers (17th to 31st). Averaged across all customer classes, Indiana ranked 28th in the nation in terms of electricity prices (2019), down from 13th in 2010. However, despite this substantial drop in national ranking, the percentage difference between prices in Indiana and the top ranking state in both years has not

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[3] Indiana Code § 8-1-2.5-6. Title 8, Article 1, Chapter 2.5 Alternative Utility Regulation. <http://iga.in.gov/legislative/laws/2020/ic/titles/008#8-1-2.5>

[4] Indiana Code § 8-1-2.5-6.

[5] Ibid.

changed significantly.[6] Within each customer class, Indiana has gone from ranking within the cheapest half of states in the nation to the most expensive half over the 2010 to 2019 period.

Figure 6. Indiana's national ranking for electricity prices by customer class (2010 versus 2019)

Source: Form EIA-861 – Annual Electric Power Industry Report (2010-2019)

In addition to Indiana's national ranking, LEI considered the State's ranking vis-à-vis its neighboring states, namely Illinois, Kentucky, Michigan, and Ohio ("the region") by analyzing and comparing:

(i) average electricity rates;

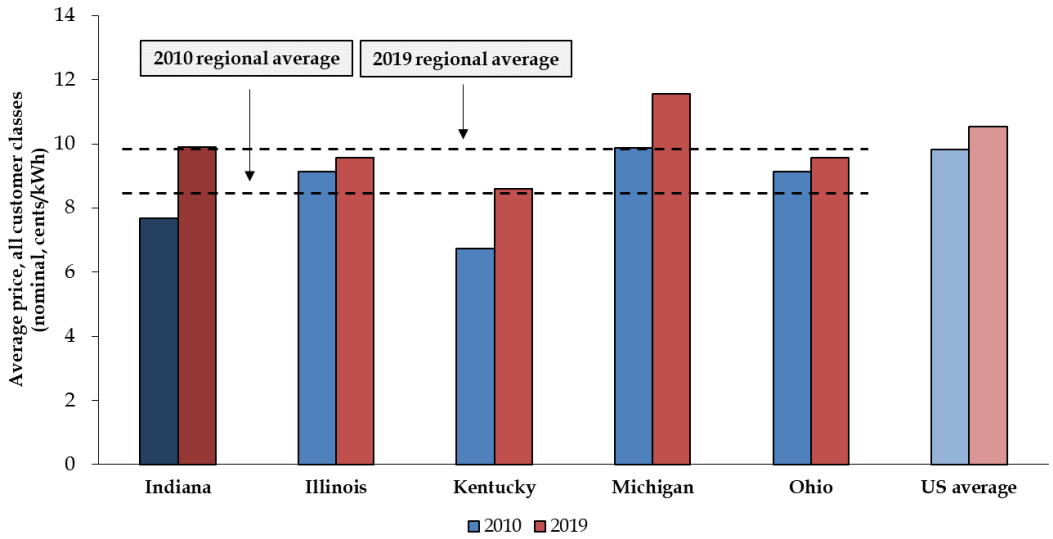
(ii) energy affordability; and

(iii) reliability.

For **average electricity rates**, LEI considered the rates charged to customers across the region over the period 2010-2019, using data from the US Energy Information Administration ("EIA") – see Figure 7. Indiana's comparative advantage of having "cheaper-than-average" energy prices as compared to neighboring states deteriorated over the period (from second lowest in the region in 2010 to fourth by 2019). Notably, over the period studied, Indiana has experienced the highest growth in residential, commercial, and industrial electricity rates of all the states in the region.

[6] In 2010, Indiana's average electricity prices across all customer classes were 24% higher than Wyoming's (which were the lowest in 2010) – 7.67 cents/kWh (IN) versus 6.20 cents/kWh (WY). By 2019, Indiana's average electricity prices across all customer classes were 29% higher than Louisiana's (which were the lowest in 2019) – 9.91 cents/kWh (IN) versus 7.71 cents/kWh (LA).

Figure 7. Average delivered electricity prices in Indiana and neighboring states (2010 and 2019)



Year	Indiana	Illinois	Kentucky	Michigan	Ohio	Regional average	US average
Average electricity prices (all customer classes)							
2010	7.7	9.1	6.7	9.9	9.1	**8.5**	**9.8**
2019	9.9	9.6	8.6	11.6	9.6	**9.8**	**10.5**
CAGR	2.9%	0.5%	2.8%	1.8%	0.5%	**1.6%**	**0.8%**
Residential							
2010	9.6	11.5	8.6	12.5	11.3	**10.7**	**11.5**
2019	12.6	13.0	10.8	15.7	12.4	**12.9**	**13.0**
CAGR	3.1%	1.4%	2.6%	2.6%	1.0%	**2.1%**	**1.3%**
Commercial							
2010	8.4	8.9	7.9	9.8	9.7	**8.9**	**10.2**
2019	11.0	9.1	10.2	11.4	9.7	**10.3**	**10.7**
CAGR	3.1%	0.2%	2.9%	1.7%	0.0%	**1.6%**	**0.5%**
Industrial							
2010	5.9	6.8	5.1	7.1	6.4	**6.2**	**6.8**
2019	7.4	6.5	5.6	7.1	6.6	**6.6**	**6.8**
CAGR	2.5%	-0.5%	1.1%	0.0%	0.3%	**0.6%**	**0.1%**

Source: US EIA. *Average Price by State by Provider, Form EIA-861, Detailed State Data.* 2020.

Generally, the electricity rates charged by IOUs and munis in Indiana have been relatively lower than those charged by the co-ops, with IOUs 24% lower and munis 19% lower per year from 2010 to 2019. However, co-ops tend to serve less densely populated regions, contributing to higher costs. The average annual growth rates in electricity costs are comparable between co-ops and munis, while the growth rate for IOUs has been higher historically.

For **energy affordability**, LEI used three metrics to assess energy affordability in Indiana and the region:

1. the home energy affordability gap ("HEAG"), which quantifies the difference between economically 'affordable' and 'actual' home energy bills for low-income households;
2. the home energy burden for low-income households as a percentage of gross income; and

3. the average percentage of households facing unaffordable energy bills.

Data showed that Indiana's HEAG was lower than the regional average for the period 2012-2019 (except in 2015), where a lower affordability gap is better. However, Indiana went from having the 3rd lowest HEAG in the region in 2012, to the 4th by 2019. Relative to the national average, Indiana's affordability gap has been higher since 2017. Moreover, low-income households in Indiana (those with incomes below 50% of the Federal Poverty Level ("FPL")) paid 30% of their annual income (on average) for their home energy bills from 2012 to 2019. Affordability may also be impacted by COVID-19. Section 9.7.2 discusses the potential impact of the COVID-19 pandemic on ratepayers.

Finally, for **reliability**, LEI assessed metrics such as the System Average Interruption Duration Index ("SAIDI"), System Average Interruption Frequency Index ("SAIFI"), and the Customer Average Interruption Duration Index ("CAIDI"). Generally, across all three metrics, Indiana's IOUs have performed slightly worse than the national average on a customer-weighted basis over the 2017-2019 period.

Overall, Indiana's rates have increased faster than the national average, and affordability has fallen, while reliability is moderately lower than national norms. Detailed analyses of each of these metrics are provided in Section 7.

1.5 Cost drivers

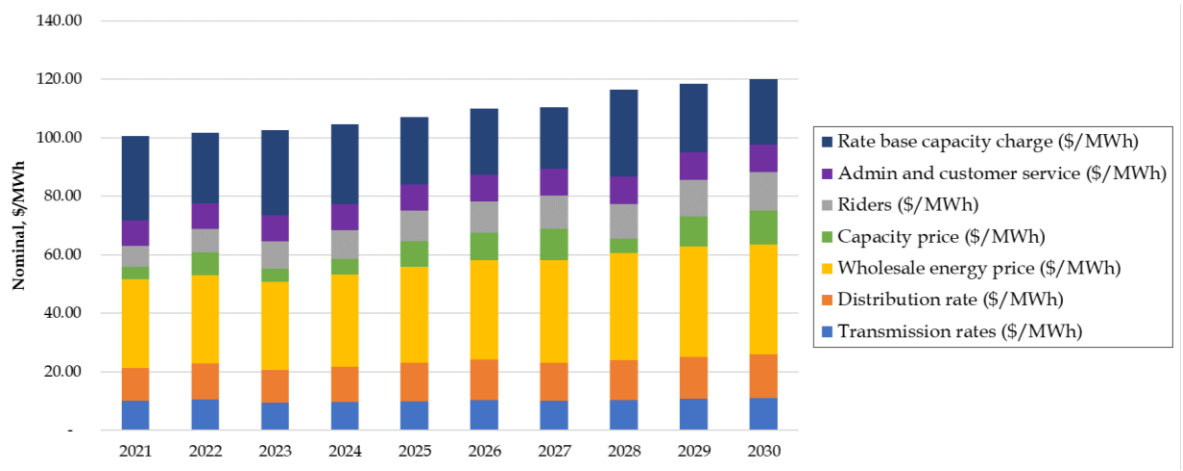
As demonstrated in Figure 7 above, Indiana's electricity prices have risen steadily in the last decade, growing at a compound annual growth rate ("CAGR") of 2.9% over the 2010 to 2019 period. This growth rate has meant that electricity prices in the State have risen faster than the national average inflation rate of 1.8% (for consumer prices) and 0.8% (for electricity prices) for the same period. This has eroded Indiana's comparative price advantage relative to its neighboring states. Rising electricity prices have primarily been driven by:

- **flattening demand,** or a lack of significant increase in demand, following the global financial crisis. Indiana's load has declined at a CAGR of -0.4% from 2010 to 2019, compared to growing at a CAGR of 0.2% from 2000 to 2009. This has translated to higher rates, as the fixed costs of providing electric service are spread across a shrinking customer base;
- significant replacement and maintenance of **aging infrastructure**, which has been facilitated partly by the Transmission, Distribution, and Storage System Improvement Charge ("TDSIC") tracker (introduced through legislation in 2013). Current TDSIC plans amount to $4.3 billion in approved investments as far out as 2026, with $1.2 billion in capital expenditures ("capex") already shouldered by ratepayers; and
- investments in **environmental retrofits** in compliance with Federal regulations. Investments totaled over $4.6 billion during the 2010 to 2020 timeframe and included projects to install pollution control equipment and convert coal units to gas.

While rate increases over the past decade in Indiana have changed its relative position among its peers, the forces pushing rates higher in Indiana are not unique. The change in relative status

may be partly a matter of timing. Going forward, it is reasonable to assume that depending on the evolution of the power sector in peer states, rates in some states may begin to rise at a rate faster than Indiana's. For example, Illinois and Ohio both face challenges with regards to whether to mandate ratepayer support for aging nuclear stations; green energy ambitions in Illinois, and to a certain extent Michigan, are likely to place upward pressure on rates in those states; and in some cases, neighboring states have significantly older infrastructure (for example, Chicago's natural gas distribution system) that requires costly upgrades.

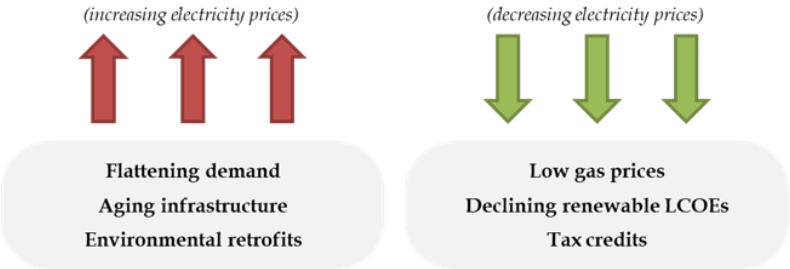
Figure 8. Forecast delivered blended energy rates in Indiana



Source: LEI analysis

Across the region, there will be upward pressure on wholesale electricity prices going forward stemming from evolving environmental regulations, electrification of transportation and heating (even if outside of Indiana), expanding energy efficiency efforts, and the possible emergence of distributed energy resources ("DERs"), where the latter two work to reduce system demand. On the other hand, there will likely be downward pressure on electricity prices from factors such as low (though gradually rising) natural gas prices and the declining costs of renewables (mainly wind and solar). Section 8 includes a detailed overview of LEI's forecast of electricity prices in Indiana, given these numerous drivers. The directional impact of these drivers is illustrated in Figure 9. LEI projects that the IOUs' blended electricity rates will increase at a CAGR of 2% in the next ten years (Figure 8). The forecast growth is slightly lower than the historical electricity rate growth from 2010 to 2019.

Figure 9. Directional electricity price impact of various cost drivers



1.6 Other considerations

Electricity-related issues are evolving, and stakeholders are increasingly engaged in the debate over the future of the power sector at the national and state level. Some of these issues include: natural gas bans; the potential growth in load due to electrification; the carbon life cycle impacts of various generation resources; the directional path for coal-fired generation going forward; issues around renewable energy siting; energy efficiency; and uncertainty around the impacts of COVID-19. These considerations are summarized briefly below, with an in-depth discussion in Section 9:

- **natural gas bans:** bans on natural gas usage are becoming central to discourses in certain states, which could have longer-term implications for Indiana if the conversation reaches more prominence at the Federal level. Changing electricity system dynamics have also led to discussions around the potential for stranded costs associated with considerable new-build gas-fired generation resources in the longer-term;
- **electrification:** increasing electrification **could** lead to significant growth in electricity consumption, peak demand, and changes in consumption patterns. Heating and transportation applications are the largest areas of potential growth in electrification for Indiana. High electrification scenarios would likely require more new-build generation capacity in the longer term, although managing consumption could reduce the overall need for this new capacity;
- **carbon and life cycle impacts of coal, natural gas, solar, and wind:** life cycle greenhouse gas ("GHG") emissions estimates for wind and solar resources are significantly lower than emissions estimates for fossil-fuel fired resources. Based on a review of a large number of Life Cycle Assessment ("LCA") studies, median life cycle GHG emissions estimates for combined-cycle natural gas are about half those of coal (although methane leakage rates are a concern). Carbon capture and storage technologies can significantly reduce emissions from fossil-fuel fired electricity generation, although they are not considered economically viable at present;
- **coal's future:** coal generation and capacity have been consistently decreasing over the past decade, and the economic and environmental factors that have impacted coal-fired resources historically are expected to continue. A significant number of coal plant retirements are expected in the next decade, with legacy costs that will continue to be repaid through electricity rates. Further pressure would emerge if more stringent environmental rules or carbon pricing policies were to be implemented;
- **renewable energy siting:** Indiana's ability to develop its theoretical wind and solar potential will largely depend on siting considerations, although this is not the only issue. Debates around renewable energy siting have already emerged as a contentious issue in Indiana, with local zoning ordinances impacting some proposed project developments. While there is no *one-size-fits-all* solution, state-level guidelines can aid local authorities in their consideration of renewable energy siting rules;
- **energy efficiency:** energy efficiency ("EE") is a useful resource in technology-neutral, least-cost system planning. It can postpone or reduce the need for new-build electricity generation, transmission, and distribution infrastructure. Therefore, EE measures should

form an important resource in utility IRPs, but the selection of EE measures should only occur if it is less expensive than generation alternatives with similar environmental characteristics. Further expansion of energy efficiency levels is possible in Indiana, although actual levels will depend on economics and barriers to participation; and

- **uncertainty around COVID's impact on load and utilities:** there is significant uncertainty around the implications of the COVID-19 pandemic on load, the possibility of demand destruction, planning around supply-side resources (both new and existing), and the implications of all these factors on ratepayers.

1.7 What can be done through the legislative process?

As Indiana seeks to refresh its energy policy, policymakers and interested stakeholders can consider related legislative efforts pursued across the country. Legislatively mandated processes already established in Indiana include the Transmission, Distribution, and Storage System Improvement Charge ("TDSIC") established in 2013 (discussed in Section 8.1.2), and the AUR Act of 1995 (mentioned previously and also discussed in Section 6.2.1).

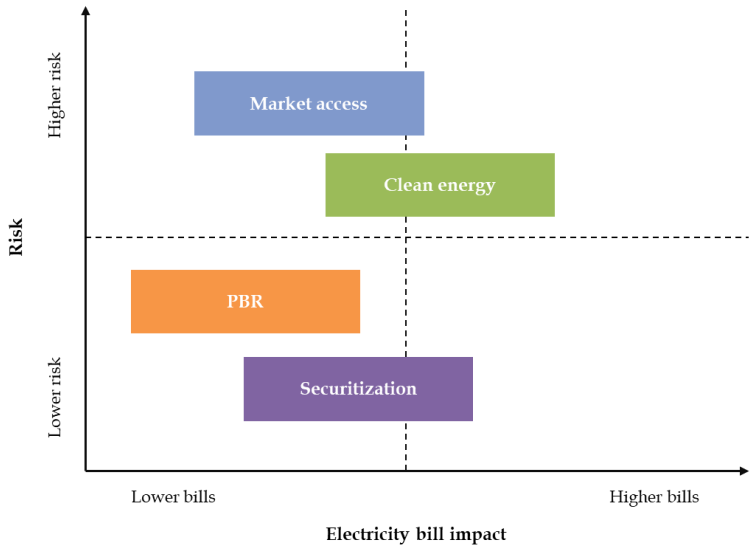
Section 10 presents a survey of legislative efforts pursued across the country, along with specific case study examples, which can be categorized into the following four areas:

- **clean energy:** arguably the most pursued state initiative in the country, with 1,500 bills related to clean energy, renewables, or emissions reductions considered in the 2019 legislative session. The most ambitious targets are being set in the Northeastern US (e.g., New York's goal is to reach 100% carbon-free electricity by 2040);
- **market access:** through the introduction of varying levels of wholesale and retail competition, some states have enabled heightened market access for generators and customers. In the region, this has been implemented in some form in Illinois, Michigan, and Ohio;
- **treatment of legacy assets:** states in the region have implemented controversial subsidies for uneconomic coal and nuclear assets (e.g., Ohio House Bill 6, which was passed in July 2019). These actions may cause additional costs to ratepayers. Meanwhile, other states across the country have enacted bills that allow securitization of these assets instead; and
- **alternative ratemaking regimes:** most states in the region (Illinois, Michigan, and Ohio) use or are in various stages of exploring performance-based ratemaking ("PBR") mechanisms.

Each of these legislative actions vary in terms of the perceived risks associated with their implementation, as well as their potential impacts on electricity bills going forward. Figure 10 provides a graphical summary of this high-level assessment, which is explained in Section 10.2.6.

Ultimately, the magnitude of risk and overall impact on electricity bills will depend on numerous interacting factors, as well as the degree to which each policy action is implemented. These considerations are explored in Section 10.

Figure 10. Risk versus bill impacts of various policy actions



Note: See Section 10.2.6 for further context regarding the placement of each of these four policy actions in the above matrix.

1.8 Goals, interests of key stakeholders, and potential paths forward

Electricity regulatory policy can be viewed as a constrained optimization process among many competing goals, with stakeholder groups rarely finding themselves completely satisfied with outcomes. In Section 11, LEI has put forward five alternative pathways that Indiana could consider for the evolution of its electricity sector:

1. **enhanced status quo**: under this pathway, traditional utilities would remain the primary engine of new investment in the sector but would be subject to a regulatory regime with an increased incentives approach, as well as a strengthened mandate to consider non-wires solutions and third party ownership alternatives to direct investment wherever possible;
2. **DER-centric**: this would build on the enhanced status quo, but would be focused on increasing opportunities for DERs, provided doing so does not result in cross subsidies. DERs are defined as small, modular, energy generation and storage technologies that provide electric capacity close to the source of load and are either connected to the distribution system or isolated from the grid in standalone applications. To promote DER opportunities, LEI envisions the following elements, among others: establishing standardized interconnection procedures; setting performance standards to ensure utilities provide DER owners with timely cost estimates; providing bill credits to DER owners for any excess generation produced; and allowing DER owners to retain the environmental attributes of their resources;
3. **baseload preservation**: this would incorporate the enhanced status quo, but would also require utilities to include in their IRPs an assessment of plans for life extension and efficiency improvements at existing coal and nuclear stations;

4. **aggressive decarbonization**: this would include all elements of the enhanced status quo and DER-centric pathways, as well as require Indiana to set a specific year to target reaching net zero emissions across the economy; or
5. **competitive wholesale market**: this would include elements of the enhanced status quo and DER-centric pathways, except that IRPs would be discontinued, utilities would be required to unbundle their generation portfolios, and competition would be introduced at both the wholesale and retail levels.

To assess each of these pathways, LEI compared their potential outcomes relative to multiple goals. Each pathway was reviewed according to criteria such as its impact on reliability, affordability, predictability, and accessibility, among others. Based on these factors, LEI's view is that there appears to be some justification for a DER-centric approach.[7]

1.9 Concluding remarks and recommendations

Indiana does not need to be a first mover in implementing any policy actions; experience in other jurisdictions can be mined to improve outcomes in Indiana. There is no need to reinvent the wheel. Best practices should be adapted to local needs; for example, if Indiana were to examine and adopt some form of PBR, any such mechanism should be tailored according to how Indiana defines performance, rather than relying on definitions established by other states that have implemented it. Likewise, were Indiana to decide to incorporate climate change into its policies, a focus on least cost approaches rather than technology specific directed procurements would likely produce better outcomes than experienced in other states.

LEI believes the State should adopt the following set of principles and activities to guide future policy and achieve reliable energy at an appropriate cost. At a high level, and as explored in-depth in Section 12, these principles and recommendations include:

- establishing a clearly defined objective function;
- maintaining a technology and ownership neutral approach;
- avoiding the support of public policy goals through electricity rates;
- recognizing the importance of optionality;
- relying on lessons learned from other jurisdictions;
- acknowledging that DERs will provide a form of competition regardless of whether the market is unbundled;
- reassessing desired levels of reliability and who pays for it;
- conducting a detailed review of rate design; and
- avoiding any sudden policy movements.

[7] See Figure 138 (page 201) and surrounding discussion for more details.

2 Understanding energy sector terminology used in this report

The energy sector is rife with confusing acronyms and esoteric concepts. To assist in reading this report, we review some relevant terms here. A list of acronyms appeared on page 10.

2.1 Energy sector basics

To begin understanding the energy sector, it is important to focus on two aspects (as illustrated in Figure 11). First, what is the ***value chain*** for the relevant fuel or technology? The term value chain refers to the full life cycle of a product as it moves from production to transport to final consumption. Second, which aspects of that value chain are ***competitive***, meaning prices are set by market forces, and which aspects are ***regulated***, with prices set according to procedures established by regulatory bodies. While all value chain segments are regulated from the perspective of health, safety, environmental impact, and consumer protection, only some have prices subject to regulatory approval. Figure 12 provides an illustration of the electricity supply value chain, differentiating between aspects of the value chain that are subject to an exclusive franchise with those that could be competitive.

Figure 11. Essential aspects for understanding the energy sector

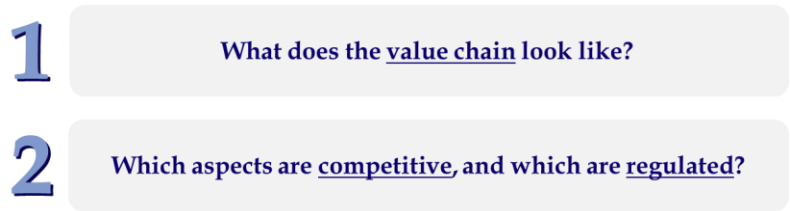
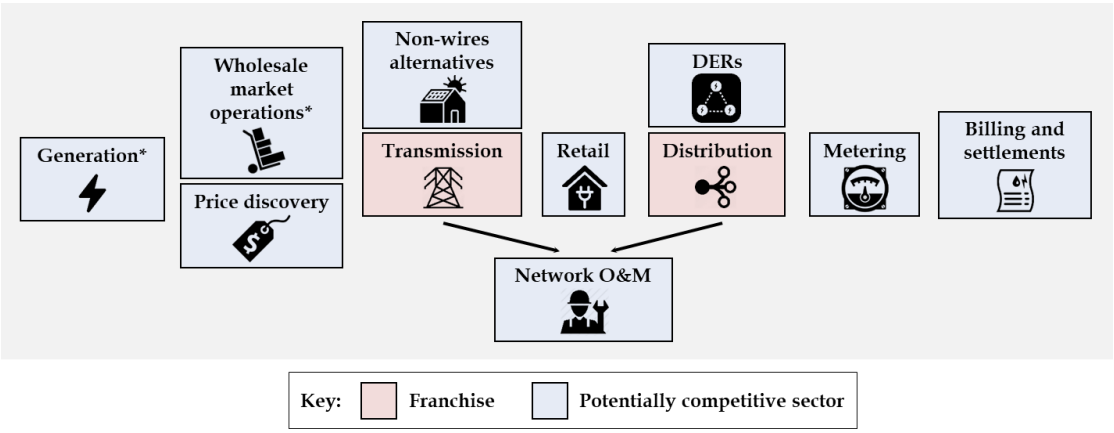


Figure 12. The electricity supply value chain



* Independent system operator ("ISO") may be deployed.

Note: DERs – distributed energy resources; O&M – operation and maintenance.

Hoosiers consume energy in a variety of ways. In some cases (gasoline, for example) they purchase the fuel directly and convert it in a vehicle or device. In others, such as electricity, the primary fuel is converted prior to delivery. Prices for coal are also market-based, and because

coal moves by modes of transportation that compete with one another (rail, truck, and barge), transport costs are also market-based. Prices for oil, natural gas, and refined products are largely unregulated; however, rates on the pipelines through which they move are regulated, meaning their final price to the consumer incorporates both the base commodity price, set by market forces, and the delivery cost, set by regulators. In some states, electricity markets have been deregulated, meaning a similar paradigm applies – market forces set the base price of electricity, but the cost of transmitting it over high voltage transmission lines and lower voltage distribution lines is regulated.

2.2 Market participants

Entities that provide often essential services as near monopolies at regulated rates are referred to as ***utilities***. Interstate oil and natural gas pipelines and transmission lines are regulated at the Federal level by the US Federal Energy Regulatory Commission ("FERC"). The North American Electric Reliability Corporation ("NERC") sets mandatory reliability standards and is overseen by FERC. ***Investor-owned*** local natural gas and electricity distribution utilities are owned by shareholders and regulated by state commissions; in Indiana, this role belongs to the Indiana Utility Regulatory Commission ("IURC"). Some utilities have different ownership structures; a ***municipal utility*** ("muni") is owned by a city or town, and sometimes regulated only by the relevant local authority; a ***co-operative utility*** ("co-op") is owned by its members and usually regulated only by its board. Coal mines, oil and natural gas producers, and generators that are not owned by utilities (sometimes referred to as ***independent power producers*** ("IPPs")) are not utilities, and are free to set their own rates.

Indiana's utilities build generation to meet their projected load based on ***Integrated Resource Plans*** ("IRPs"), which must be filed with the IURC every three years. IRPs are intended to force utilities to consider a range of technologies and resources to meet future needs; these resources can include conservation and demand response, based on the theory that if it costs less to encourage beneficial changes to demand than it does to build a new power plant to meet that demand, the utility should consider energy efficiency programs in lieu of new construction.

In addition to using generation from facilities that they own, Indiana utilities also purchase power from IPPs and the wholesale market. In some states, utilities only transmit power, and customers can arrange for their own supplies through competitive retailers who participate in wholesale markets on their behalf. Wholesale electricity markets in the US Midwest and Northeast are organized around ***Independent System Operators*** ("ISOs").[8] Two ISOs serve Indiana, the Midcontinent ISO ("MISO") (highlighted in orange in Figure 13), and the PJM Interconnection ("PJM") (highlighted in yellow). ISOs coordinate flows on the transmission lines in their region, identify transmission investment needs, and also run markets for a set of products (energy, capacity, ancillary services ("A/S"), and transmission congestion rights). Utilities retain ownership of the transmission lines and the responsibility for physically maintaining them; the

[8] Some ISOs are also referred to as ***Regional Transmission Organizations*** ("RTOs").

ISO's role is to make sure that the capacity on those transmission lines is allocated fairly to facilitate competition among generators.

NERC, ISOs, the IURC, and utilities all have a role with regards to maintaining system reliability. NERC sets technical standards for reliability and monitors utility performance; ISOs manage and plan the transmission system consistent with NERC standards, and utilities justify future generation and distribution system investments to the IURC as being needed to meet NERC standards.

While ISOs differ in how they define the products that they optimize, generally, ***energy*** refers to the production from a generator (or amount of load reduction made available) that is transmitted to consumers for instantaneous use. ***Capacity*** can be thought of as a sort of reservation payment, intended to assure that sufficient generation and load reduction is available to meet maximum expected requirements; given the need for a reserve margin, there will inevitably be some resources which run infrequently, yet need to be maintained. Some portion of reserve capacity needs to be held ready to run, but not yet providing energy, to assure that when demand fluctuates, increases in load can be immediately met. This portion of reserve capacity that is standing ready to run immediately receives ***ancillary services*** payments for the period when it is not providing energy. A plant or demand reduction resource can receive payments for all three services. ISOs also facilitate markets in hedges against ***transmission congestion***; those that purchase the hedges can avoid additional charges during periods when transmission lines are fully loaded. Figure 13 presents a map of US ISOs and Figure 14 lists Indiana utilities participating in MISO and PJM.

Figure 13. Map of US ISOs

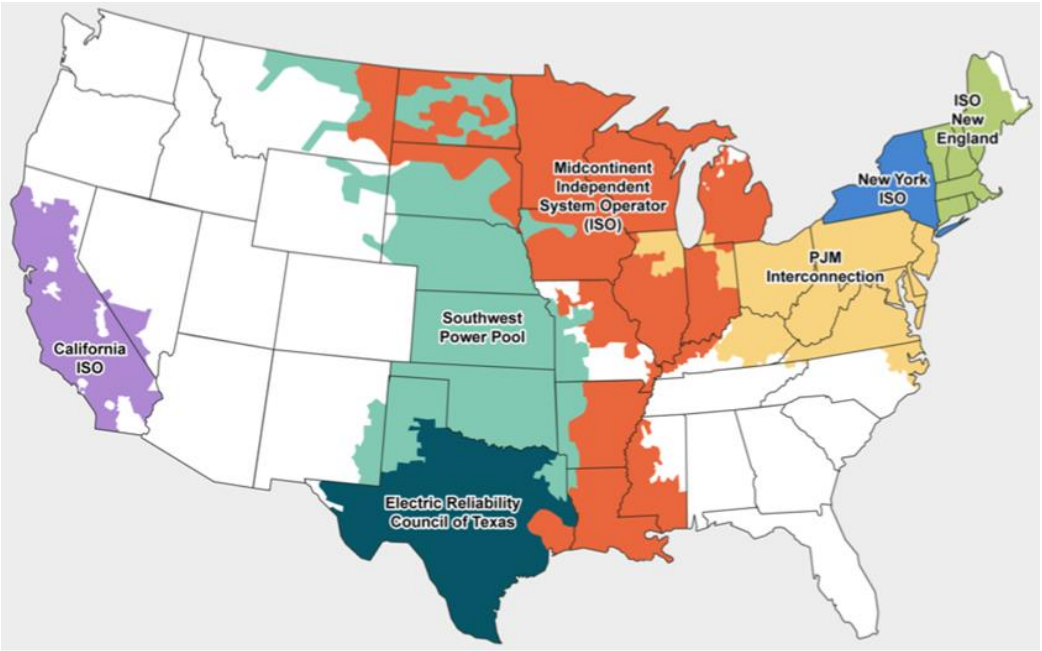


Figure 14. Indiana utilities participating in MISO and PJM

Characteristics	MISO	PJM
Participating Indiana utilities	Duke, NIPSCO, IPL, Vectren, AEP, Hoosier Energy, IMPA, and WVPA	AEP *(including its Indiana subsidiary I&M)*, IMPA, and WVPA
Transmission lines (across footprint)	71,800 miles	84,236 miles
Generation capacity (across footprint)	175,528 MW	180,086 MW
Annual billings	$29.9 billion	$49.8 billion
Headquarters	Carmel, Indiana	Audubon, Pennsylvania

Sources: Indiana Office of Utility Consumer Counselor ("OUCC"), MISO Corporate Information, and PJM website.

2.3 Rate design

Utility regulation is often said to rest upon a ***regulatory compact***, in which utilities are granted exclusive franchises and an ***obligation to serve*** in exchange for being allowed to charge ***just and reasonable*** rates. Just and reasonable has been interpreted in North America to mean rates which provide an investor the opportunity to achieve a return consistent with that which could be received in an unregulated industry facing a similar level of risk, provided service expectations are met. Returns are not guaranteed, however. Rates are also expected to be ***non-discriminatory***, in that groups of customers with similar characteristics are treated in the same way.[9]

Electric utilities in Indiana are ***vertically integrated***; this means that they own assets across the value chain, including generation, transmission, and distribution. The basis for setting rates is what is known as ***cost of service*** (see Section 6.3 for an overview of the rate setting process under a cost of service regime). Simplistically, a utility adds up all of its costs (the total of which is referred to as its ***revenue requirement***) and allocates them across its customers, who are sometimes referred to as ***ratepayers***. Costs include capital costs associated with the construction of generating stations, transformers, wires, poles, and associated infrastructure (collectively, the ***rate base***), divided by the number of years of expected service; operating costs, which are largely related to the cost of employees; and the cost of capital, which is the return on ratebase and compensates lenders and shareholders of the utility. Some costs are charges on a per unit (usually a kilowatt-hour ("kWh")) basis, meaning customers only pay based on what they use; some are charged based on peak demand (per kilowatt, or "kW") other costs are charged on a per customer basis, meaning a portion of the customer's bill is not impacted by usage. Rates may be based on forecast or historical costs; in either case, a true up to actual costs may be necessary periodically.

A key principle of rate design is ***cost causation***, meaning that the rates that customers pay should reflect the costs that their usage imposes on the system. Because devices that store electricity have historically been expensive (though the technology is improving in this regard), the entire system (generating stations and transmission and distribution facilities) needs to be built so as to instantaneously meet potential peak demand, plus a reserve margin in case portions of the system

[9] FERC. *An Overview of the Federal Energy Regulatory Commission and Federal Regulation of Public Utilities.* June 2018.

are unavailable at peak times. Based on cost causation, customers that contribute disproportionately to peak load are charged higher rates than those that do not. Utilities often segment their customers into industrial, commercial, and residential load, and charge different rates to each. Residential customers often pay the highest rate because they consume a higher proportion of their load at peak times. By contrast, industrial rates are often lowest because many industrial customers consume at a more or less steady level throughout the day, and some may not be connected at a distribution voltage, thus using less of the system.

While cost of service is the foundation for rate-setting across North America, some jurisdictions have been experimenting with ways to incorporate better incentives for utilities into rates. The implementation of ***performance-based ratemaking*** ("PBR"), coupled with specific service quality standards, is seen in some jurisdictions as a way to encourage efficiency while guiding utilities to focus on areas of greatest priority to policymakers. Under PBR, utilities that meet efficiency or other objectives are allowed to earn a bit more than the target cost of capital, while ratepayers benefit from rates that may increase more slowly due to the associated efficiency gains. As discussed in Section 6.2, Indiana's rate design includes some incentive properties, but does not fully incorporate PBR.

2.4 Other important concepts

When wholesale power becomes available more cheaply than resources built under ratebase, assets are sometimes referred to as "stranded." ***Stranded assets*** are often long-lived assets built many years ago which are less efficient than current resources, or use a more costly fuel. In some cases, utilities can provide benefits to ratepayers by not running plants that they own, and substituting their output with purchases on the wholesale market. However, in the meantime, the utilities need to recover the remaining cost of the asset that is no longer being used. In such circumstances, in some states, regulators have allowed the utilities to retire the stranded asset while stretching out the recovery period for the remaining cost so that existing customers are not as burdened by the repayment.

Many states have enacted policies to encourage renewable or zero-emitting resources. Often the basis for these policies is a ***renewables portfolio standard*** ("RPS"). The RPS requires utilities, or in cases that allow them, retailers, to procure a specified percentage of their load from a set of qualifying resources. Qualifying resources vary from state to state, but normally include wind, solar, hydro, and biomass, though the definitions within these categories may also differ. Utilities and retailers often are allowed to demonstrate that they have met the RPS requirement by purchasing the necessary amount of ***renewable energy certificates*** ("RECs"). Qualifying resources receive RECs for each megawatt hour ("MWh") that they produce; they are then able to sell these RECs to utilities and retailers that need them to meet their RPS requirements.

Declining technology costs, Federal incentives, and smaller unit sizes have contributed to the proliferation of ***distributed energy resources*** ("DERs"). DERs are generally small scale, and often renewable, resources connected at a distribution voltage or situated behind the meter ("BTM"). The term can encompass storage and dispatchable load as well. Some commentators see the potential for DERs to reconfigure the electricity supply network, resulting in two-way flows on the distribution system and reducing the need for larger, centralized generating stations. DERs

can also be used as non-wires alternatives ("NWAs") to defer capex in the distribution or transmission system. However, DERs pose challenges to utilities and ISOs, as they may not be able to forecast or control production from these resources. This poses challenges for coordination, planning, and optimization.

3 About the Study

LEI was engaged by the Indiana Chamber of Commerce Foundation ("ICCF") in June 2020 to conduct an Indiana energy policy study and report ("the Study").[10] LEI was selected by ICCF to review "Indiana's energy needs, production, consumption, pricing, economic impacts, public policy options and regulatory systems."[11] LEI is a US-owned and operated company based in Boston and Chicago, with over two decades of experience providing advisory services in the energy industry. The project kick-off was held on June 19, 2020.

3.1 Scope of work

The goals of the Study are to:

1. offer a solid foundation to assist policymakers, consumers, and other stakeholders in understanding how the industry and its regulation works;
2. provide an understanding of how things have changed. A notable component here relates to rising energy costs, although other issues to be addressed include the energy mix, reliability, and regulatory considerations (to name a few);
3. provide reliable information on how things could develop going forward. Again, an important component here relates to costs, but it is not the only area of concern; and
4. identify options that are available to address issues discovered in the Study (e.g., lower costs or reduce growth rate trajectory of costs, enhance reliability), determine the avenues available to make such changes (e.g., legislative process, regulator), and suggest a list of recommendations most useful to all stakeholders and policymakers.

To achieve these goals, LEI created this report to provide a deeper understanding of the factors driving energy changes in Indiana and the region. The report covers the following topics, as illustrated in Figure 15: an overview of Indiana's energy resources, electricity industry, and regulatory framework; a comparison of the State's national and regional ranking for electricity costs, affordability, and reliability; a discussion of the factors that have driven and will continue to drive cost changes in Indiana and the region; a review of other considerations; a discussion of what can be done through the legislative process; and an overview of the goals of various stakeholders.

Throughout the Study, LEI has compared Indiana's energy sector relative to other states in the region. For the purposes of this Study, "region" is defined as the following neighboring states: Illinois, Kentucky, Michigan, and Ohio (see Figure 16). These states were selected due to their proximity to Indiana, as well as their similarities with the state. LEI also reviewed national rankings in terms of average electricity rates, energy affordability, and reliability.

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[10] Contract between ICCF and LEI signed on June 12, 2020.

[11] ICCF. *Request for Proposals: Indiana Energy Policy Study.* April 1, 2020. p. 1.

Figure 15. Issues examined in the Study

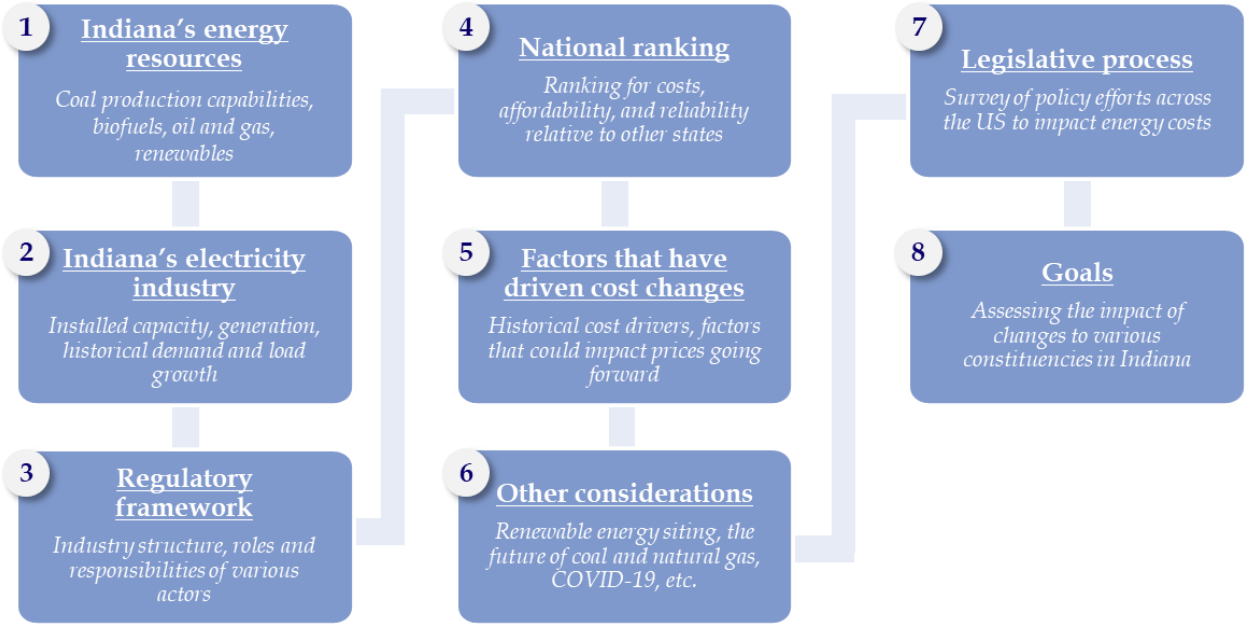
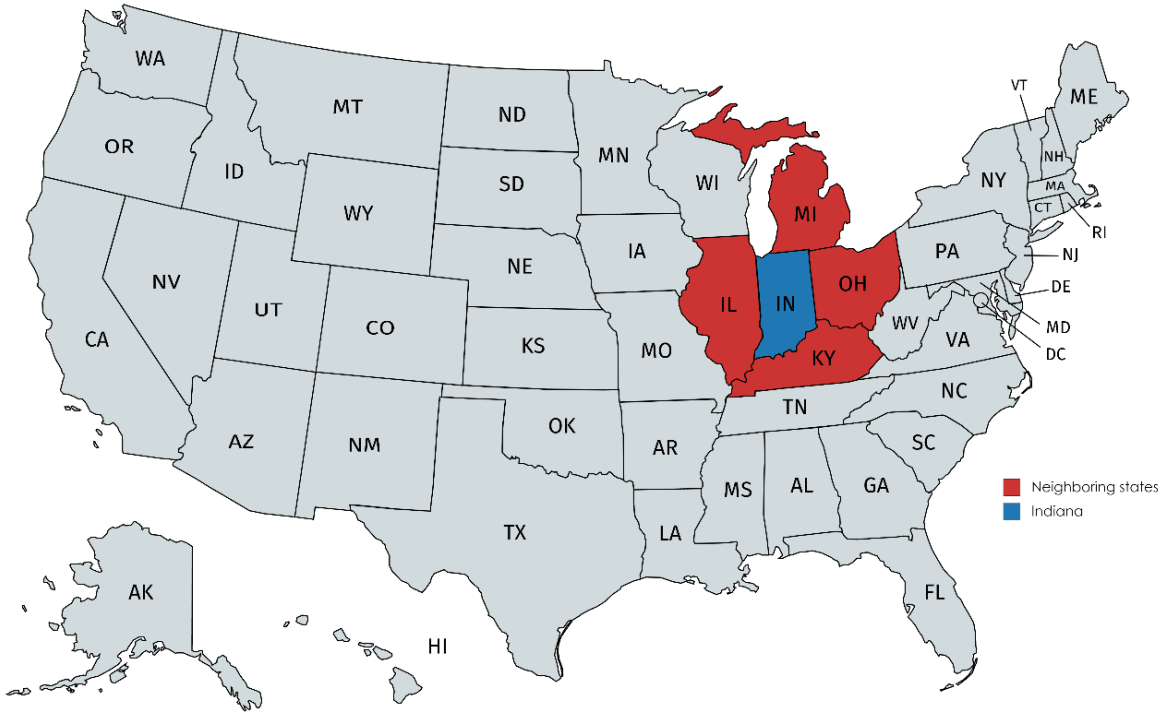


Figure 16. Map of the states included in this Study



3.2 Process

Throughout the Study, LEI conducted a thorough review of over 230 documents and held six virtual calls with ICCF and various stakeholder entities to obtain their input and inform our analysis. The following subsections provide further details regarding the data sources consulted, as well as the stakeholders LEI interacted with during the engagement.

3.2.1 Data sources

LEI's analytical work relied on publicly available data and information from various state and Federal sources, including but not limited to: relevant state statutes, Indiana Utility Regulatory Commission Decisions and Orders, utility reports, the US Energy Information Administration ("EIA"), the US Department of Energy ("DOE"), FERC, news articles, as well as third-party commercial databases to which the firm subscribes.

The following key literature was consulted to inform the analyses (Appendix A, page 217, provides a complete list of documents reviewed in this Study):

- utility integrated resource plans;
- IURC. *2020 Annual Report.* 2020;
- IURC. *2020 Report to the 21st Century Energy Policy Development Task Force.* August 14, 2020;
- IURC. *Indiana Utility Guide.* 2019 Edition;
- MISO. *MISO Transmission Energy Plan.* 2019;
- State Utility Forecasting Group ("SUFG") for the IURC. *Indiana Electricity Projections: The 2019 Forecast.* November 2019;
- US EIA. *Annual Electric Power Industry Report, Form EIA-861 detailed data files.* 2020; and
- US EIA. *State Energy Data System ("SEDS"): 1960-2018 (complete).* June 26, 2020.

3.2.2 Stakeholder input

LEI also talked with and gathered the views of stakeholders on the issues relevant to this Study. LEI conducted virtual meetings with stakeholders in early October 2020, including representatives from energy producers, utilities, and industrial consumers. In addition to ICCF, LEI also consulted with the following stakeholders: EDP Renewables, the Indiana Energy Association ("IEA"), the Indiana Industrial Energy Consumers, Inc. ("INDIEC"), and Sunrise Coal LLC.

3.3 Caveats

The analyses in this Study were not intended to account for all circumstances in the future. None of the results provided in subsequent analyses should be taken as a promise or guarantee as to the occurrence of any future events. The Study focused on Indiana as a whole, and outcomes may differ regionally within Indiana.

4 Indiana's energy resources

Indiana produces and consumes a wide range of energy resources, including fossil fuels (coal, oil, and natural gas) and renewable resources (including biomass products such as biofuels and wood and waste energy, as well as wind, solar, hydroelectric, and geothermal). A visual representation of Indiana's production and consumption of energy by source for 2018 using EIA data appeared in Figure 2.

For fossil fuels, coal has served as the dominant energy source on both the production and consumption side, although both the production and consumption of coal has seen a downward trend over the past decade. Crude oil and natural gas production in the State were comparatively minimal, but natural gas and petroleum-based energy consumption was significant. As a net consumer of energy, Indiana relies on other states for a portion of what it consumes. For renewables, the production of biofuels and consumption of biomass (which includes fuel ethanol) were the dominant energy sources, followed by wind. Other renewable resources include solar, hydroelectric, biomass, and geothermal. Although there are no nuclear plants located in Indiana, nuclear plays an important role in Indiana's overall electricity supply mix. Around 11% of the electricity consumed in the State comes from out-of-state nuclear.

4.1 Coal

Indiana has an abundance of coal resources. According to the US EIA, in 2019, Indiana produced around 32 million tons of coal, making it the nation's 7th largest coal producer (approximately 4.5% of US total coal production).[12,13] As shown in Figure 17, Indiana's coal resources are concentrated in the Illinois basin around the southwestern portion of the State. In 2019, production was further concentrated at ten surface and five underground mines.[14,15] According to estimates published by the National Mining Association ("NMA"), in 2017, coal mining contributed $1.26 billion directly to Indiana's Gross Domestic Product, with an additional $1.39 billion in indirect and induced economic contributions.[16]

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[12] US EIA. *Quarterly Coal Report, October-December 2019*. April 2020

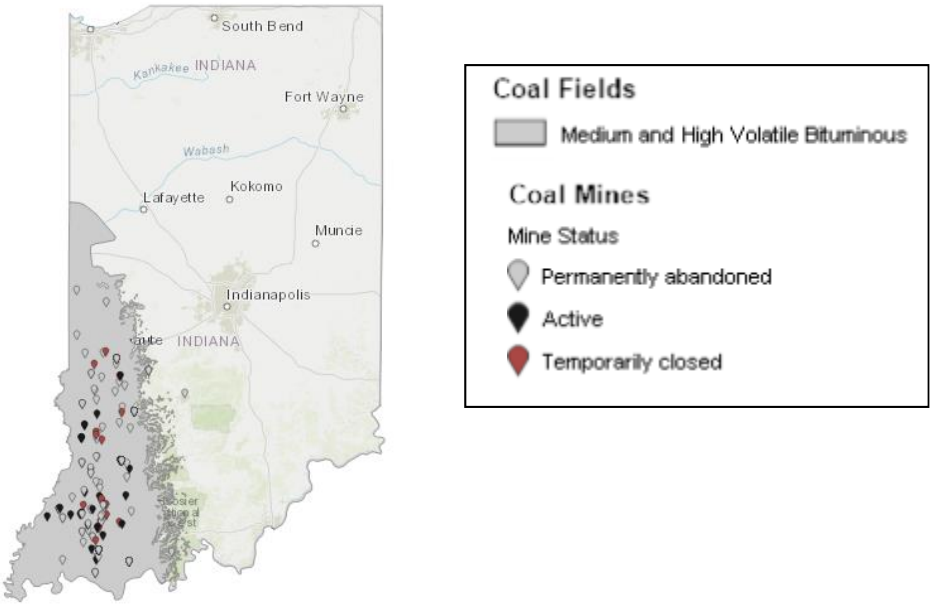
[13] Ton refers to short ton, equivalent to 2,000 pounds.

[14] Based on the mine names listed in Indiana Department of Natural Resources. *Indiana Coal Production for Year 2019*. February 17, 2020.

[15] Surface mines are usually within a few hundred feet of the surface, making it easier to remove earth above coalbeds, which can then be mined. Underground mines require tunneling into the earth, with the coal being mined underground. See the EIA's glossary for definitions of surface mines and underground mines.

[16] The National Mining Association. *The Economic Contributions of U.S. Mining (2017 Update)*. September 2018.

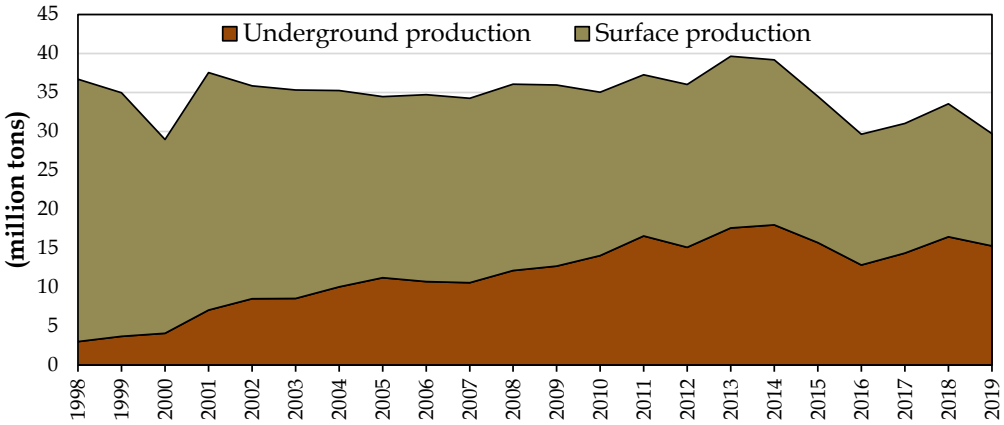
Figure 17. Map of Indiana's coal fields and mines



Source: Third-party commercial database.

Most of Indiana's coal production over the past two decades has occurred at surface mines. However, as shown in Figure 18, there has been a noticeable increase in coal produced through underground mining – with coal generated through underground mining making up just over 50% of total coal production for the first time in 2019.[17]

Figure 18. Annual coal production by mine type (underground or surface) in Indiana, 1998-2019



Note: The drop in coal production starting from 2015 matches the general decline seen at the national level.

Sources: Indiana Coal Council's information on *Indiana Coal Production*, from 1998-2019.

[17] Using data from the Indiana Coal Council. Based on EIA data, coal produced through underground mining overtook surface mining in 2018.

In terms of Indiana's coal capabilities, the EIA produces information on:

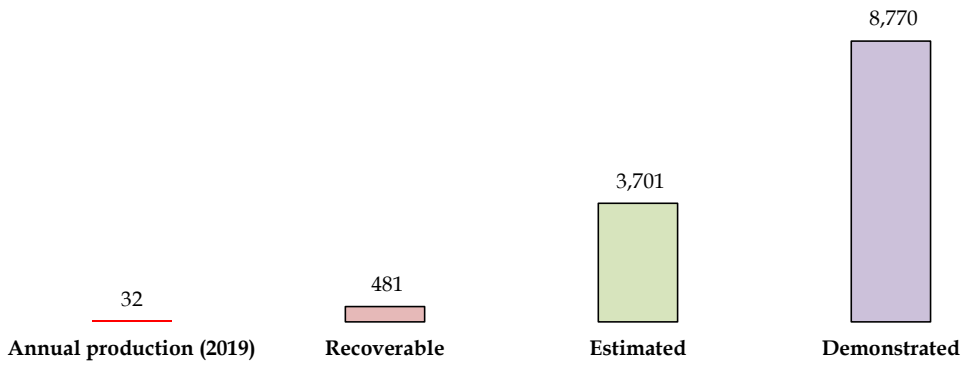
i. **recoverable coal reserves at producing mines**, which, as the name suggests, represents the amount of coal that can be extracted from producing mines;

ii. **estimated recoverable reserves**, which represents an estimate of coal reserves "based on a demonstrated reserve base, adjusted for assumed accessibility and recovery factors, and does not include any specific economic feasibility criteria;"[18] and

iii. **demonstrated reserve base**, which includes "publicly available data on coal mapped to measured and indicated degrees of accuracy and found at depths and in coalbed thicknesses considered technologically minable at the time of determinations."[19]

Figure 19 presents the EIA data for the above three items, as well as Indiana's 2019 coal production for reference. Based on this information, using 2019 production levels: recoverable coal reserves at producing mines will last around 15 years, estimated recoverable reserves will last over 100 years, and the demonstrated reserve base would last closer to 300 years. Of these estimated and demonstrated reserves, underground reserves make up the vast majority (around 95%). Alternate sources, such as the Indiana Geological and Water Survey ("IGWS"), have put Indiana's total amount of unmined coal at around 57 billion tons, of which approximately 17 billion is "recoverable using current technology" – with around 12% recoverable through surface mining and 88% through underground mining.[20]

Figure 19. Indiana's coal reserves and production (million tons)



Note: Underground coal reserves make up 36%, 94%, and 95% respectively of recoverable, estimated, and demonstrated reserves.

Source: US EIA. *Recoverable Coal Reserves at Producing Mines, Estimated Recoverable Reserves, and Demonstrated Reserve Base by Mining Method, 2018.*

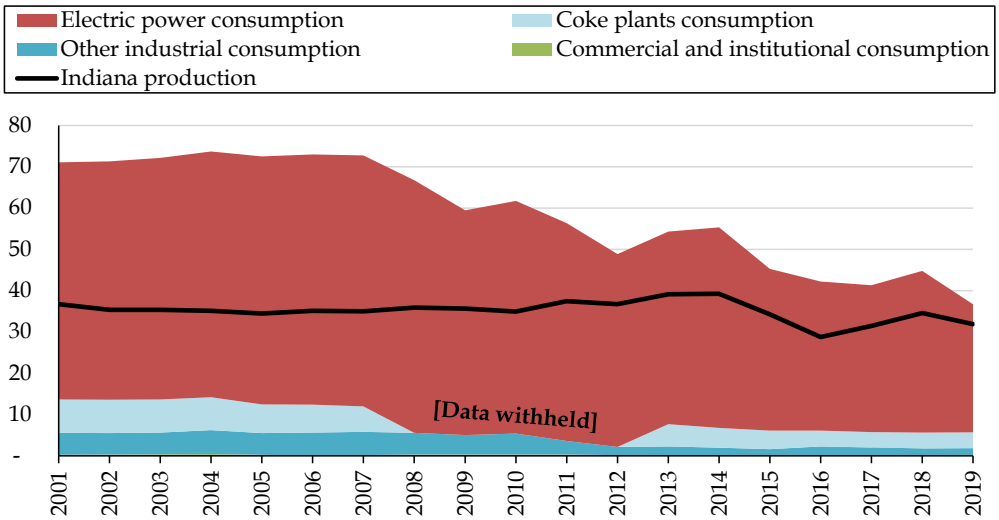
[18] Taken from EIA's glossary definition of *Estimated Recoverable Reserves (coal)*.

[19] Taken from EIA's note on demonstrated reserve base, from: *Recoverable Coal Reserves at Producing Mines, Estimated Recoverable Reserves, and Demonstrated Reserve Base by Mining Method*. 2018.

[20] Indiana Geological and Water Survey. Coal in the US and Indiana. Last accessed July 25, 2020.

However, for the period up to 2019, Indiana's annual coal consumption has exceeded its production, with the State being the nation's second largest consumer of coal. As shown in Figure 20, coal's primary usage on the consumption side relates to the generation of electricity (where thermal coal is burned in boilers to produce steam that generates electricity). Coal is also used by industrial customers and at coke plants (which can use metallurgical coal to supply coke for the steel industry).[21] Figure 20 demonstrates that the gap between production and consumption has decreased dramatically over the past two decades, driven primarily by a decline in coal-fired electricity generation.

Figure 20. Indiana's annual coal consumption by sector and total coal production, 2001-2019 (million tons)



Note: The decline of 'coke plants consumption' to zero for 2008-2012 is due to EIA data being withheld to prevent ownership disclosure.

Sources: Consumption data taken from EIA's coal data browser, consumption dataset; production data taken from EIA's *Annual Coal Reports* from 2001-2018, and *Quarterly Coal Report* for October-December 2019.

4.2 Oil

Although Indiana has a long history of oil production, the State's production rates have declined noticeably from the highs seen in the 1950s and 1960s.[22] Crude oil production, concentrated around the Illinois basin, was around 1.6 million barrels in 2019 – the lowest level seen over the 1960 to 2019 data presented in Figure 21. Likewise, the State's proved crude oil reserves have also declined,

Proven energy reserves are estimated quantities of energy sources that analysis of geologic and engineering data demonstrates with reasonable certainty are recoverable under existing economic and operating conditions.

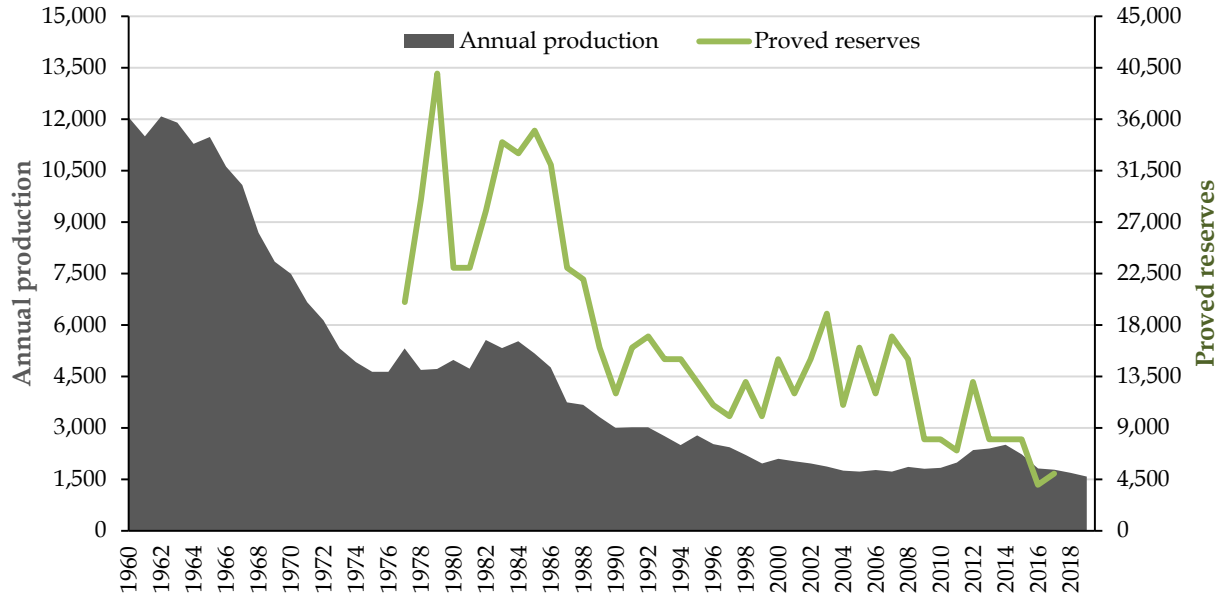
Source: EIA

[21] Coke oven gas can (is) also captured to produce other energy – including electric energy – at steel mills.

[22] A longer-term oil production figure from the IGWS can be viewed here.

from a high of around 40 million barrels in 1979 to around 5 million barrels in 2017. Further exploration and Indiana's oil reserve potential will depend on oil price trajectories and technological advancements going forward.

Figure 21. Indiana's crude oil annual production and proved reserves, 1960-2019 (thousand barrels)

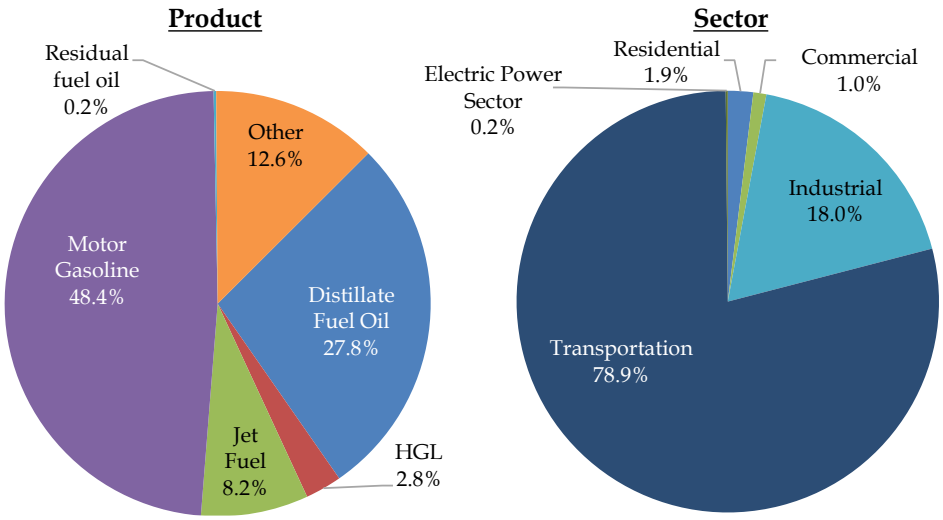


Sources: EIA data on Crude Oil Proved Reserves and Primary Energy Production.

On the consumption side, petroleum energy products are consumed in large amounts and rank third after coal and gas in terms of primary fuel sources. Petroleum products consumed consist mainly of motor gasoline and distillate fuel oil (Figure 22). These products are consumed largely by the transportation sector, followed in a distant second by the industrial sector. Residential consumption of petroleum energy products is low, comprising primarily of hydrocarbon gas liquids ("HGL") such as propane, with minimal usage of distillate fuels for heating.[23]

[23] Based on information from the EIA's State Energy Data System, and Indiana State Energy Profile.

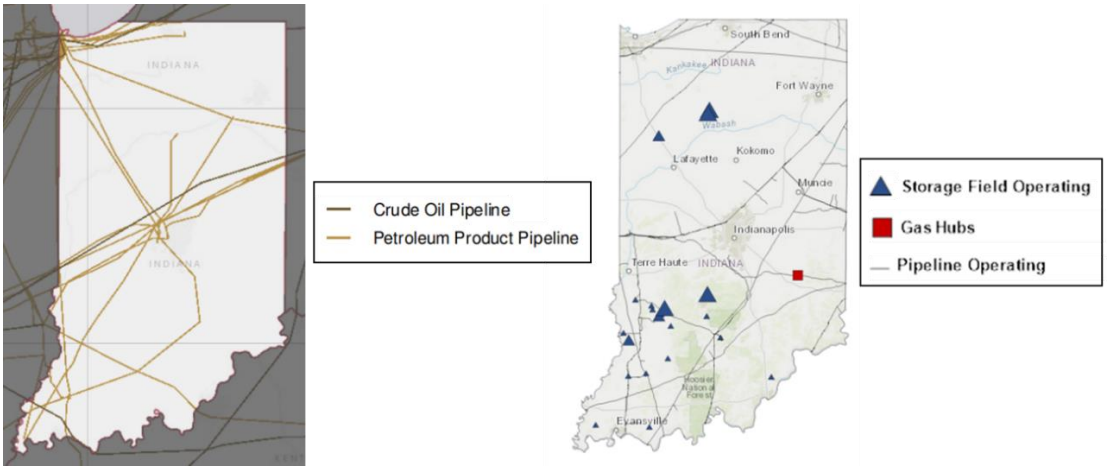
Figure 22. Consumption of petroleum energy by product and sector in Indiana (2018)



Source: Based on information from the EIA's State Energy Data System. Final data for 2019 to be released on June 25, 2021.

Indiana's network of oil and petroleum product pipelines are shown in Figure 23 (see map on the left). In addition, the State hosts two petroleum refineries, including the Whiting Refinery. Whiting is the largest refinery in the Midwest. It can process around 430,000 barrels of crude oil per day, produce around 10 million gallons of gasoline, 4 million gallons of diesel, and 2 million gallons of jet fuel (as of 2019).[24]

Figure 23. Indiana's oil and petroleum pipeline infrastructure (left) and gas pipeline and storage infrastructure (right)



Source: US EIA, Indiana Profile Overview, Crude Oil Pipeline, and Petroleum Product Pipeline layers, accessed July 27, 2020; third party commercial database.

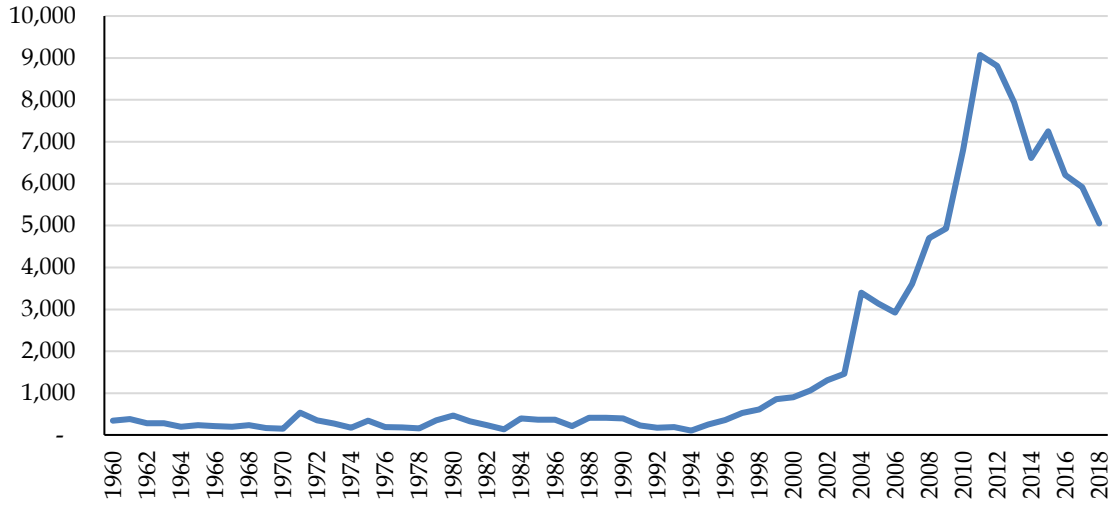
[24] BP. *Whiting Refinery*. September 2019.

4.3 Natural gas

Natural gas production in the State has increased significantly since the 1990s, as shown in Figure 24. Production peaked in 2011 at around 9,000 million cubic feet ("MMcf") but has since declined to around 5,000 MMcf by 2018 (0.02% of the national total). Producing gas wells are concentrated in the central-eastern and southwestern portions of the State.[25]

Nationally, Indiana ranked 23rd in terms of natural gas production in 2018. Indiana's proved natural gas reserves are not significant, with proved reserves between 0% and 0.02% of the nation's total.[26]

Figure 24. Natural gas production in Indiana, 1960-2018 (million cubic feet)



Note: By comparison, in 2018, Ohio produced 2,403,382 MMcf of natural gas and Pennsylvania produced 6,264,832 MMcf.

Sources: EIA data on Primary Energy Production.

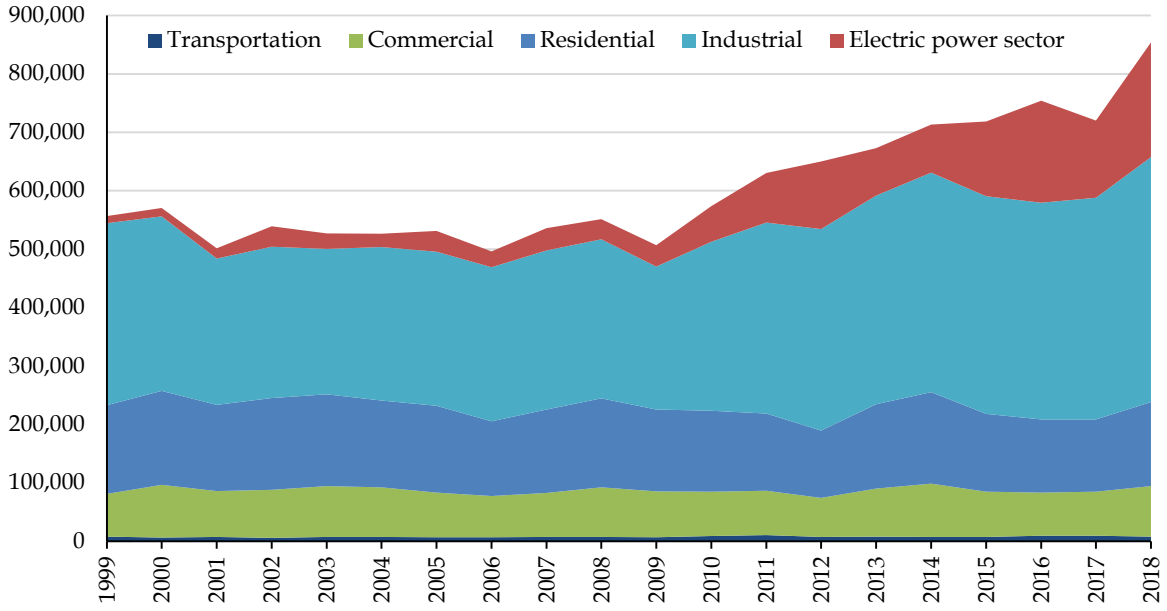
While Indiana's gas production is limited, natural gas plays a pivotal role in the State, ranking second after coal in terms of primary fuel sources on the consumption side, and serving as the price-setting resource in wholesale markets. As shown in Figure 25, natural gas usage has increased noticeably over the past two decades. The main drivers of this increase relate to surging usage of natural gas in the electricity generation sector, as well as increases in gas consumption at the industrial level (which ranked second and first, respectively, in terms of natural gas consumption in 2018). The residential sector accounted for around 17% of natural gas consumption in 2018, with gas serving an important role in the provision of space heating. In Indiana, the majority of households rely on natural gas (60% of households) as their primary

[25] Indiana Geological and Water Survey. A Brief Overview of the History of the Petroleum Industry in Indiana. Last accessed July 27, 2020.

[26] Based on information in US EIA. *U.S. Crude Oil and Natural Gas Proved Reserves, Year-End 2018*. December 2019.

energy source for space heating, followed by electricity (30%), hydrocarbon gas (mostly propane, 7%), and fuel oil or kerosene (less than 1%).[27]

Figure 25. Annual natural gas consumption in Indiana, 1999-2018 (million cubic feet)



Sources: EIA data on Primary Energy Consumption.

Indiana's network of natural gas infrastructure is shown in Figure 23 (see map on the right). Interconnections run through all four bordering states and include nine interstate natural gas pipelines, which as of 2019 had a total inflow capacity of 18,140 MMcf per day (ranked 11th nationally) and a total outflow capacity of 15,785 MMcf per day (ranked 6th nationally).[28] Indiana's 21 storage facilities (Figure 23) had a combined storage capacity of around 114 billion cf in 2018 (ranked 19th nationally).[29]

[27] US EIA. *Indiana State Energy Profile.* June 18, 2020.

[28] US EIA. US state-to-state capacity data. January 22, 2020.

[29] US EIA. *Indiana State Energy Profile.* June 18, 2020.

4.4 Biofuels

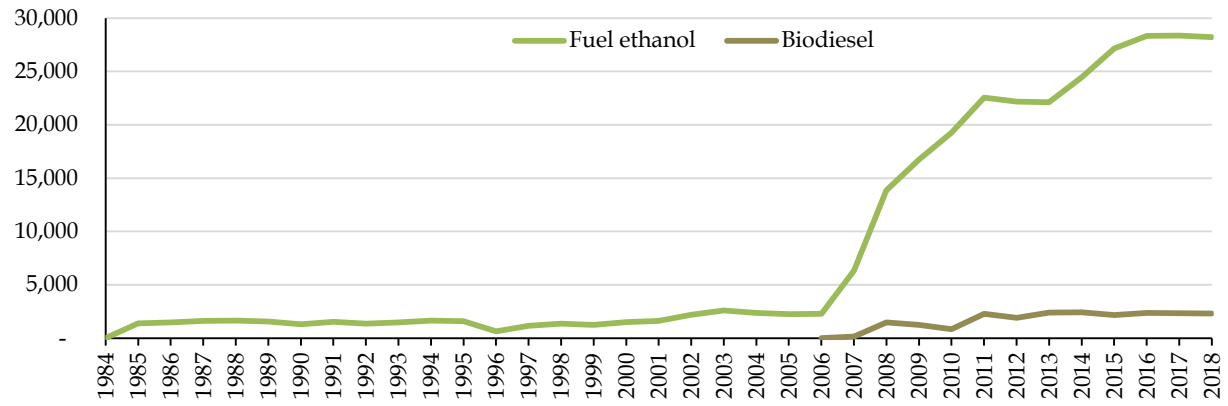
Indiana produces large amounts of renewable biofuels, notably fuel ethanol and biodiesel. In 2018, around 28.2 million barrels of ethanol and 2.3 million barrels of biodiesel were produced in the State, ranking 5th nationally in the production of both (around 7% and 5% of the national total, respectively).[30] As presented in Figure 26, production of both biofuels started taking off around 2007/2008, although fuel ethanol has always been produced in larger quantities.

In terms of capacity, as of 2018, Indiana's 14 ethanol production sites had a total production capacity of 80 million barrels per year, while its three biodiesel production sites had a production capacity of around 7 million (with biodiesel capacity largely concentrated at a single site in the Northeast).[31] A map of these sites is shown in Figure 27.

Fuel ethanol is an alcohol-based renewable fuel derived from plant materials such as corn, which can then be blended with gasoline.

Biodiesel is a renewable fuel derived from a variety of sources including soybean oil, corn oil, and other plant and animal fats. Biodiesel can be blended with petroleum diesel or used directly as a diesel replacement.

Figure 26. Annual production of fuel ethanol and biodiesel in Indiana, 1984-2018 (thousand barrels)



Note: Fuel ethanol production numbers include denaturant.

Sources: US EIA's State Energy Data System, production dataset.

On the consumption side, in 2018, Hoosiers consumed around 7.1 million barrels of fuel ethanol, attributable almost entirely to the transportation sector (around 97%), with the remainder consumed in similar proportions within the commercial and industrial sectors.[32] For biodiesel, consumption in 2018 was just under 1 million barrels, attributable entirely to the transportation

[30] Based on information from the US EIA's State Energy Data System ("SEDS").

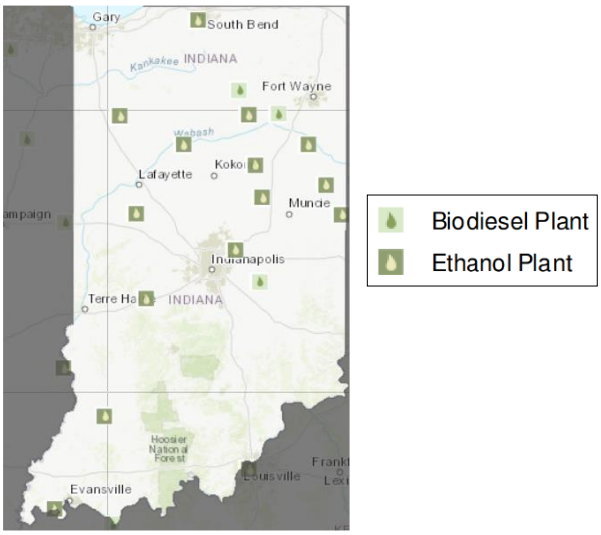
[31] Based on information from the US EIA's fuel ethanol and biodiesel production capacity reports.

[32] Based on information contained in the US EIA's State Energy Data System, consumption dataset.

sector.[33] As briefly covered previously, the blending of biofuels with petroleum-based products for use in the transportation sector is relatively common, and according to the US Department of Energy ("DOE"), around 98% of gasoline nationally contains some ethanol. The most common blend for ethanol is E10, which contains 10% ethanol (and 90% gasoline), while E85 (or "flex fuel") contains between 51% and 83% ethanol, and can be used in vehicles specifically designed to run on the E85 blend.[34] Similarly, biodiesel can also be blended with petroleum diesel (e.g., B20, which contains up to 20% biodiesel), but can also be used directly as diesel fuel (B100, which is pure biodiesel).

Given Indiana's relatively large production and capability of fuel ethanol and biodiesel, biofuels are one energy resource where Indiana is a net producer (i.e., in-state production exceeds in-state consumption).

Figure 27. Map of Indiana's ethanol and biodiesel plants



Source: US EIA, *Indiana Profile Overview, Biodiesel Plant, and Ethanol Plant Map Layers*, accessed August 13, 2020.

4.5 Renewables

4.5.1 Wind

Indiana's wind resources provide significant theoretical electricity generation potential. Estimates include high end potential for 118,388 megawatts ("MW") of installed wind capacity, which could produce around 351,000 gigawatt hours ("GWh") of electricity, more than three times the State's current total electricity consumption.[35] Based on information from the US DOE's WINDExchange website, assuming turbine heights of 80 meters, a lower technical potential of

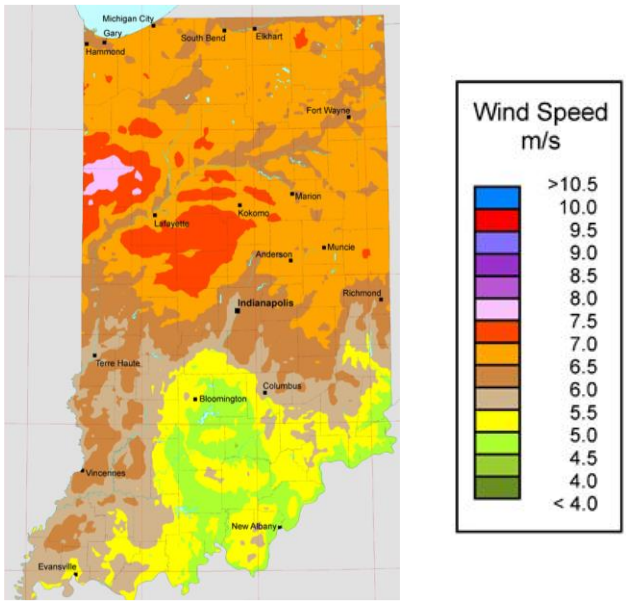
[33] Based on EIA consumption database.

[34] US Department of Energy's Alternative Fuels Data Center. Ethanol Fuel Basics. Accessed August 13th, 2020.

[35] Based on information from the US DOE's wind exchange website, which sources AWS Truepower and NREL.

40,259 MW exists in Indiana over an area of 8,250 square kilometers, or around 9% of Indiana's total landmass.[36] This technical potential wind capacity would be able to produce an amount greater than Indiana's total annual electricity consumption, albeit not matching the times where this consumption takes place, and likely requiring additional transmission infrastructure. For reference, Figure 28 presents a map of the State's estimated wind speeds at 80-meter heights.[37] As illustrated in the map, the northern parts of the State have higher wind speeds, with the best wind speeds located around the central-west region.[38, 39]

Figure 28. Estimate for annual average wind speed at 80-meter heights in Indiana



Source: AWS Truepower and NREL, Wind resource estimates developed by AWS Truepower, LLC.

The information above on wind capacity provides estimates for technical potential and is not meant to represent the economically feasible or socially acceptable amount of wind that can be developed in Indiana. Nevertheless, Indiana's wind resources have provided a new source of

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[36] Based on information contained on the US DOE's wind exchange website, including the Indiana Potential Wind Capacity Chart and the associated Wind Resource Exclusion Table. Land can continue to be farmed or put to other productive uses as and after a wind facility has been developed.

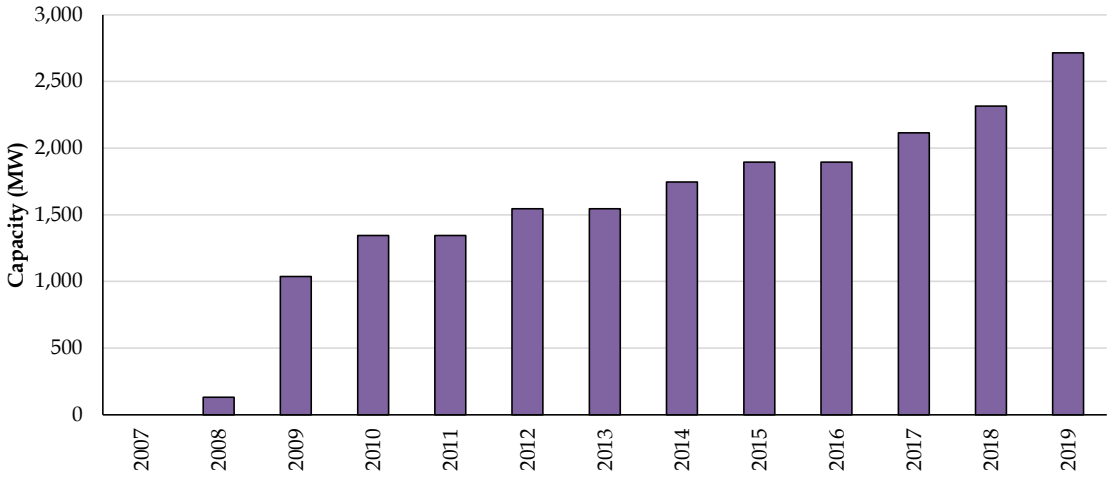
[37] Wind speeds can be expected to increase at higher heights, meaning more electricity production per turbine. Maps of wind speeds at various heights can be viewed here.

[38] A map of existing wind developments in Indiana can be viewed through the US Wind Turbine Database, which provides a highly interactive map of existing wind developments across the US at the turbine level.

[39] Offshore wind in the Great Lakes represents a potential but untested area for new energy development. A number of concerns stand in the way, including freezing waters, impacts on wildlife, regulatory considerations, and overall economics. The outcome of the potential IceBreaker wind project, a 20.7 MW demonstration wind farm that could be developed in Lake Erie off of Ohio's coast (or similar Great Lakes developments), may provide valuable insight into the longer-term viability of offshore wind development in the Great Lakes, including Lake Michigan.

energy that has grown significantly over the past two decades, as illustrated in Figure 29. As of the first quarter of 2020, Indiana's total installed wind capacity was around 2,317 MW,[40] ranking 12th in the nation in terms of wind capacity (2% of the national total), and producing around 6% of the State's total electricity.[41] Potential additions to Indiana's wind capacity are covered subsequently in Section 5.2.1.

Figure 29. Growth in installed wind capacity in Indiana (cumulative MW)



Sources: 2007 data from US DOE website; 2008 to 2019 data based on the State Utility Forecasting Group *2019 Indiana Renewable Energy Resource Study* (September 2019).

4.5.2 Solar

Solar generation is a nascent industry in Indiana. As a gauge of the State's solar potential, Figure 30 presents Indiana's solar irradiance as measured in kilowatt-hours per square meter per day.[42] Solar irradiance is higher in southwestern Indiana as compared to the rest of the State, although the irradiance levels are still lower than those seen in states such as Arizona, California, and Nevada (for reference, average net solar capacity factors for utility-scale solar systems in 2018 were estimated at 30.3% in Arizona, 29.7% in Nevada, 29% in California, and 19% in Indiana).[43]

Solar irradiance is the amount of solar energy that arrives at a specific area of a surface during a specific time interval.

Source: NREL's solar resource glossary

Although Indiana's solar irradiance levels are moderate, solar's contribution to Indiana's energy base has grown since 2013 (as shown in Figure 31), due in large part to technological

[40] The American Wind Energy Association. *Wind Energy in Indiana* (April 2020).

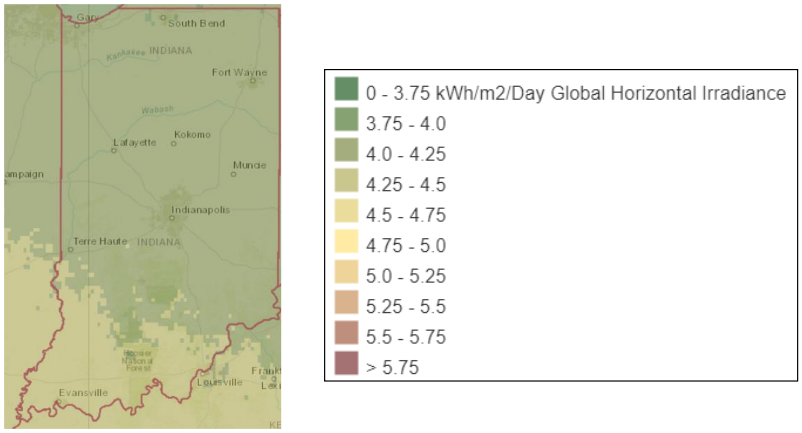
[41] Based on information from US EIA data.

[42] Specifically, the figure depicts Global Horizontal Irradiance ("GHI").

[43] Berkley Lab's Electricity Markets and Policy Department. Utility Scale Solar, PV Capacity Factors visualization. Accessed September 20, 2020.

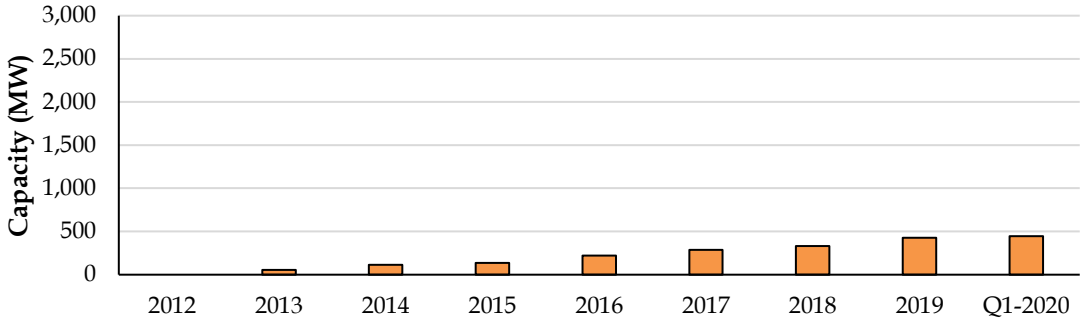
improvements and falling costs, as well as various government and other incentive programs. According to the State Utility Forecasting Group ("SUFG"), as of July 2019, Indiana had a total solar photovoltaic ("PV") installed capacity of 322 MW.[44] According to the Solar Energy Information Association, Indiana's total installed solar capacity through to the first quarter of 2020 was around 445 MW, with most coming from utility solar installations.[45] In addition, although there are no statewide community solar policies in place in Indiana to date, some individual utilities do offer community solar programs.[46] In total, solar provided around 0.3% of the State's net electricity generation in 2019,[47] although this is expected to increase in the coming years as planned solar facilities come online. Potential additions to Indiana's solar capacity are covered subsequently in Section 5.2.1.

Figure 30. Indiana's global horizontal solar irradiance



Source: US EIA, Indiana Profile Overview, Solar Resources Map Layer, accessed July 26, 2020.

Figure 31. Growth in installed solar capacity in Indiana (cumulative MW)



Source: Solar Energy Information Association's *State Solar Spotlight – Indiana*

[44] State Utility Forecasting Group. *2019 Indiana Renewable Energy Resource Study*. September 2019.

[45] Solar Energy Information Association. *State Solar Spotlight – Indiana.* June 2020.

[46] NREL. *Indiana.*

[47] Based on information from EIA Form 923.

Battery storage

Although not a renewable resource, battery storage technologies can be beneficial in aiding to firm and balance intermittent renewable resources, as wind and solar projects increase their penetration. Battery storage technologies can be deployed on a standalone basis or paired with intermittent renewable resources to store excess renewable generation for consumption during periods of higher demand (and can also provide a wide range of other benefits). Battery storage technologies remain relatively expensive, but have seen significant cost declines over the past decade. For example, Bloomberg New Energy Finance estimated that lithium-ion battery pack prices fell by 85% over the 2010-2018 timeframe. Expectations going forward are that storage technologies will continue seeing cost declines and performance improvements (e.g., improving cycling ability, longer duration of storage). However, storage may not be cost competitive with natural gas fired peaking plants until after 2030, depending on the assumed cost of carbon emissions.

As of 2019, installations by Indiana utilities were around 44 MW (mainly lithium-ion batteries). In the longer term, assuming continued cost declines and performance improvements, storage could serve as a valuable component in Indiana's overall energy mix.

4.5.3 Geothermal

Indiana uses its geothermal resources for heating and cooling purposes, for example, through geothermal heat pumps than can provide winter heating and summer cooling. According to the EIA, in 2018 Indiana ranked 6th nationally in terms of geothermal energy consumption; most of this was concentrated at the residential level (3.8 trillion British thermal units or "Btu"), with commercial consumption at around 0.8 Btu. This was around 2.2% of the US total geothermal energy consumption in 2018, and around 0.3% of Indiana's total energy consumption.[48]

Geothermal energy as a source of electricity generation is not viewed as having significant potential in Indiana. As shown in Figure 32, the eastern side of the State has geothermal potential which the EIA categorizes as "least favorable," while the western side of the State has geothermal potential that is only slightly better. Geothermal energy resources for electricity generation in Indiana have been described by the EIA as "minimal,"[49] while the Indiana Office of Energy Development ("OED") notes that "Indiana's geology is not conducive [to] geothermal electricity plants."[50]

Therefore, the addition of geothermal energy resources in the State will likely relate to its provision of heating and cooling, focusing on decisions being made at the individual residential and commercial levels.

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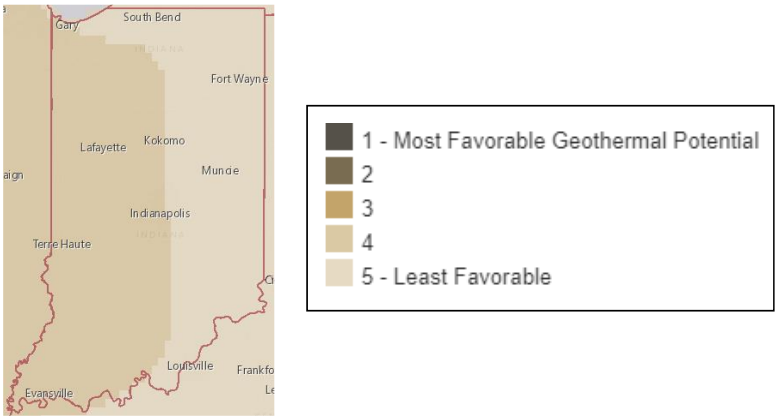
[48] Based on information from the EIA's State Energy Data System.

[49] Based on the following quote: "Indiana's geothermal energy resources are minimal, and there are no geothermal power plants in the state." Source: US EIA. *Indiana State Energy Profile*. Accessed July 26, 2020.

[50] Indiana OED. Geothermal: Energy Basics. Accessed July 26, 2020.

Figure 32. Indiana's geothermal potential



Source: US EIA, Indiana Profile Overview, Geothermal Potential Map Layer, accessed July 26, 2020.

4.5.4 Other biomass (wood and waste)

Historically, wood and waste biomass served as Indiana's leading renewable energy source, up until the rapid growth in biofuels (notably fuel ethanol) and wind energy.

Wood-based biomass is derived from wood and wood processing wastes, residues, and byproducts. For example, Indiana's wood-based biomass production includes four wood pellet plants that in 2020 can produce 102,700 tons of wood pellets, which can be used for heating purposes.[51] According to the US Environmental Protection Agency ("EPA"), Indiana's waste-based biomass energy resources include 22 operational landfill gas energy projects and municipal solid waste landfills, with a total nameplate electricity generating capacity of around 66 MW and around 27 million cf of landfill gas flowing to project.[52]

Waste energy includes: municipal solid waste, landfill gas, methane, digester gas, liquid acetonitrile waste, tall oil, waste alcohol, medical waste, paper pellets, sludge waste, solid byproducts, tires, agricultural byproducts, closed loop biomass, fish oil, and straw used as fuel.

Wood energy includes: wood and wood products used as fuel, including round wood (cord wood), limb wood, wood chips, bark, saw dust, forest residues, charcoal, pulp waste, and spent pulping liquor.

Source: EIA's glossary of terms

Historical wood and waste energy production from 1960 to 2018 is shown in Figure 33. Wood-based biomass has historically produced more energy than waste-based biomass. However, following the growth in waste-based biomass energy in 1986, and the declines in wood-based biomass energy around the same time, energy production from these two biomass groupings has reached a point of relative equality in 2018.

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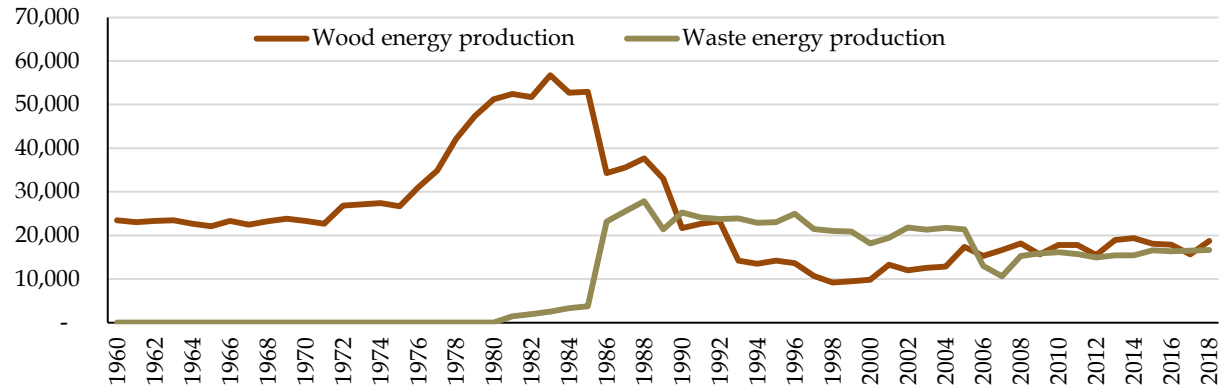
[51] Biomass Magazine. US Pellet Plants. Accessed August 13th, 2020.

[52] US EPA. Landfill Methane Outreach Program (LMOP), Project and Landfill Data by State Database. Accessed August 13, 2020.

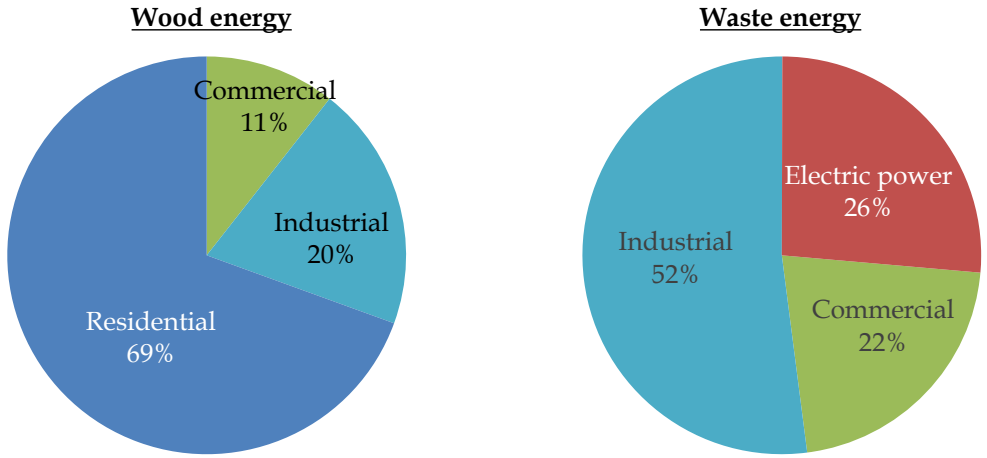
On the consumption side, in 2018, wood and waste energy made up around 1% combined of the State's total energy consumption, although the sectors in which this consumption occurred differ. As shown in Figure 34, wood-based biomass energy was consumed predominantly in the residential sector (e.g., for heating purposes), followed by the industrial and commercial sectors. For waste-based biomass energy, a little over half was consumed in the industrial sector, with the remainder split between the commercial and electric power sectors (around 460 GWh of biomass-based electricity production in 2018).[53]

Figure 33. Historical wood and waste energy production in Indiana (billion Btu)



Sources: US EIA's State Energy Data System, production dataset.

Figure 34. Consumption breakdown of wood and waste energy by sector in Indiana (2018, percentage)



Source: US EIA's State Energy Data System, consumption dataset.

Small-scale expansion of production capacity for wood and waste biomass may be feasible, for example, through the expansion of capacity at candidate landfills, farms, or waste facilities.

[53] Based on information from the US EIA's Electricity Data Browser.

However, as these biomass resources typically require inputs that are considered byproducts or residues, large-scale expansion is less likely.

4.5.5 Hydro

Hydro power is a very small portion of Indiana's total generation. Hydroelectric resources can be broken down into three forms:

i. resources from existing hydroelectric facilities (powered dams);

ii. potential resources at existing non-powered dams ("NPD"), which are existing dams that do not generate electricity, but are used to provide a variety of services including regulating water supply and controlling inland navigation;[54] and

iii. potential resources through the development of new dams.

In 2019, Indiana's five **existing hydroelectric** generation facilities, which had a combined nameplate capacity of 92 MW, produced a net generation of around 256 GWh (around 0.2% of Indiana's total net electricity generation from all sources).[55]

According to a report produced by the US DOE, Indiana's potential capacity from **NPDs** was around 454 MW,[56] while their combined output could be around 2 GWh.[57] Most of this potential capacity (close to 80%) was concentrated at two dams on the Ohio river owned by the Corps of Engineers Great Lakes and Ohio River Louisville District ("CELRL"), with capacity being split equally between Indiana and Kentucky.[58]

Moreover, according to a 2014 DOE report analyzing the potential for **new hydroelectric development projects** in undeveloped stream-reaches (i.e., those that do not have powered or non-powered dams), Indiana's potential new capacity was estimated at 581 MW, while potential generation was estimated at 3,123 GWh.[59]

It should be noted that the DOE's estimates for hydroelectric capacity at NPDs and undeveloped stream-reaches focused on theoretical potential, and was not meant to represent practical development of hydroelectric resources (including economic, environmental, and regulatory constraints associated with hydroelectric development). As new hydro development is generally viewed as having high up-front capital costs as well as many regulatory considerations, the theoretical potential can be viewed as an upper-bound on Indiana's hydroelectric resource

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[54] US Department of Energy. *An Assessment of Energy Potential at Non-Powered Dams in the United States*. April 2012.

[55] Based on information from a third-party commercial database and EIA form 923.

[56] US Department of Energy. *An Assessment of Energy Potential at Non-Powered Dams in the United States*. April 2012.

[57] LEI estimate using the implied capacity factor from the *John T. Myers Locks Dam* and *Newburgh Locks & Dam,* multiplied by Indiana's total NPD capacity estimate.

[58] US Department of Energy. *An Assessment of Energy Potential at Non-Powered Dams in the United States*. April 2012.

[59] US Department of Energy. *New Stream-reach Development: A Comprehensive Assessment of Hydropower Energy Potential in the United States*. April 2014.

potential, and reaching this upper-bound is not realistic. Nevertheless, using the above information, Indiana's upper-bound for total hydroelectric production can be estimated at 5,287 GWh, which is around 5% of the State's 2019 net electricity generation from all sources.

4.6 Nuclear

There are no nuclear facilities operating in Indiana, although 65% of the output from Indiana Michigan Power's 2,278 MW Donald C. Cook ("Cook") nuclear plant (located in Michigan) is dedicated to Indiana retail customers. As a result, nuclear plays an important role in Indiana's overall electricity supply mix, supplying approximately 10% of electricity consumed in the State as of 2019, according to the IURC. Indiana Michigan Power's operating licenses for Cook expire in 2034 (Unit 1) and 2037 (Unit 2), although life extension is technically possible.[60]

Expansion of nuclear energy to include in-state resources would face significant hurdles. The construction of new traditional nuclear facilities is generally not viewed as economic, with projects running the risk of going over budget and over schedule; as large, capital-intensive, long-life assets, traditional new-build nuclear plants carry significant risks amidst a changing energy environment. Existing nuclear facilities also face some of the same economic challenges, with state support being required in some instances to keep plants online.

In this regard, small modular reactors ("SMRs") are seen as a potential future generation resource that may overcome many of the issues associated with traditional nuclear reactors. SMRs are compact and scalable versions of traditional nuclear reactors, and are proposed as a safer, more flexible, and economic generation resource relative to traditional nuclear facilities.[61] However, SMRs are an untested resource, and there is no certainty on whether their potential will be realized.

4.7 Cogeneration

Cogeneration, or combined heat and power ("CHP") systems are primarily installed by industrial customers in Indiana, as they offer "an efficient and clean approach to generating on-site electric power and useful thermal energy from a single fuel source."[62] Alongside electric generation, CHP systems recover thermal energy that would otherwise be wasted at a conventional power plant and instead reuses this energy in other applications, such as in industrial production (e.g., food processing, ethanol production), for cooling, dehumidification, space heating, or to heat water to

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[60] Sources: Indiana Michigan Power's 2018-2019 IRP; IURC's 2019 Annual Report; American Electric Power's 2019 Annual Report; Indiana Michigan Power's "Nuclear Industry Overview" presentation before the Indiana 21st Century Energy Policy Development Task Force (October 17, 2019).

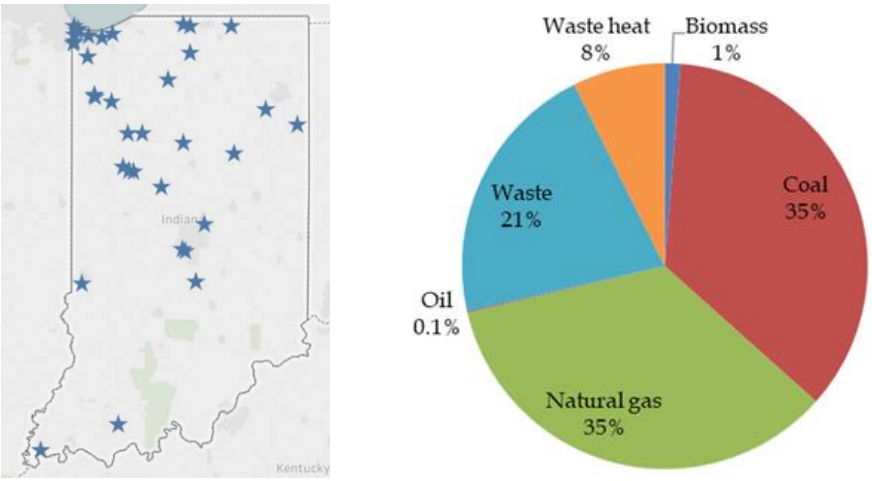
[61] US Office of Nuclear Energy. *Advanced Small Modular Reactors (SMRs).* <https://www.energy.gov/ne/nuclear-reactor-technologies/small-modular-nuclear-reactors>

[62] US DOE. *CHP Technical Assistance Partnerships.* September 2019.

be used in other production processes.[63] This allows CHP systems to operate at increased efficiency levels relative to traditional systems (up to 80% versus less than 50%, respectively).[64]

According to the US DOE, CHP systems are currently in use at 43 sites throughout Indiana, totaling 2,418 MW of capacity (data as of August 31, 2020).[65] Systems range in size from between 30 kW to 800 MW. They are primarily used in primary metals (63%) and petroleum refining (26%) applications. Figure 35 demonstrates the location of these sites, as well as a breakdown of CHP capacity by fuel type. As is shown in the chart, CHP systems in Indiana generally rely on coal (35%) and natural gas (35%) for their primary fuel source.

Figure 35. Map of CHP installations in Indiana and breakdown of CHP capacity by fuel type



Source: US DOE. *Combined Heat and Power Installations in Indiana.* August 31, 2020.

As another means for reducing the need for utility-owned generation capacity, large industrial customers in Indiana also provide interruptible load to utilities. Through contractual agreements, or interruptible load contracts, industrial customers can secure reduced rates in exchange for reducing their power consumption during peak periods.[66]

[63] OUCC. *Cogeneration: Frequently Asked Questions.* December 2015.

[64] Ibid.

[65] US DOE. *Combined Heat and Power Installations in Indiana.* August 31, 2020.

[66] IURC. *Indiana Utility Guide.* 2019.

Key takeaways

- Coal has historically been Indiana's dominant energy resource in terms of reserves, production, and consumption, although coal's production and consumption has seen a downward trend over the past decade. While production and proven reserves of oil and gas are comparatively much lower, oil and gas are still important resources on the consumption side, with natural gas in particular growing in usage over the past decade.
- Indiana's biofuels, notably fuel ethanol, are an important foundation of its renewable and total energy production base. Biofuels are one energy resource where Indiana's in-state production exceeds its in-state consumption.
- Other renewable energy resources have grown in usage over the past decade and are expected to continue growing. This is particularly true for wind and solar, largely due to technological improvements, declining costs, and various government and other incentive programs.
- Out-of-state nuclear plays an important role in Indiana's overall electricity supply mix, although expansion of nuclear resources to include traditional in-state facilities is not being considered.
- Cogeneration systems are an important resource primarily for industrial customers in Indiana, and are used mostly in primary metals and petroleum refining applications.

5 Indiana's electricity industry

Indiana's electricity generation mix is dominated by coal (59% as of 2019), followed by natural gas (31%) and wind (6%) resources. This electricity is delivered to Indiana residents by approximately 115 utilities, including five investor-owned utilities ("IOUs"), 72 municipally-owned utilities ("munis"), and 38 rural electric membership cooperatives ("REMCs" or "co-ops"). Information regarding electricity prices is covered in Section 7.

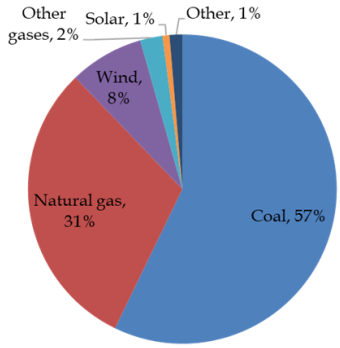
5.1 Overview

Indiana's electricity industry comprises 29,676 MW of installed capacity as of the end of 2019, with coal, natural gas, and wind ranking as the dominant fuel sources for generation assets located in-state. A snapshot of Indiana's key electricity statistics is illustrated in Figure 36.

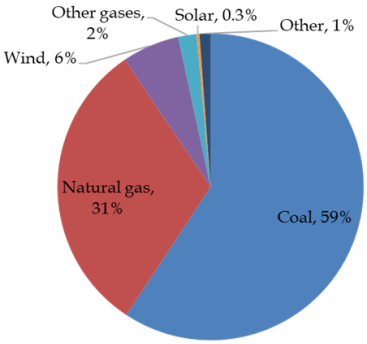
Figure 36. Snapshot of Indiana's electricity industry

Key facts	Indiana	National ranking
Installed capacity (2019)	29,676 MW	16
Generation (2019)	102.5 TWh	14
Demand (2019)	102.1 TWh	11
Load growth (2015-2019)	-0.6%	36
Transmission lines (2019)	13,200 miles	-
Population (2019)	6.7 million	17
GDP growth (nominal, 2015-19)	3.6%	20

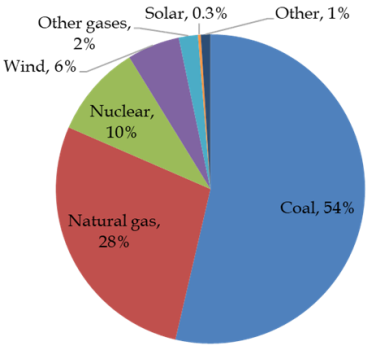
Installed capacity by fuel type (2019)



Total generation by fuel type (2019)



Electricity demand by fuel type (2019) incl. out-of-state resources



Note: Installed capacity and total generation by fuel type capture assets within Indiana only. Power plants located outside of Indiana but serving Indiana customers are not included. Generation from these assets (e.g., I&M's Cook nuclear plant) is captured in the electricity consumption by fuel type data.

Sources: US EIA data; IURC. *Annual Report.* 2019; third party commercial database; US Bureau of Economic Analysis.

As of 2019, coal accounted for 57% of the State's total installed capacity, followed by natural gas (31%), and wind (8%). In terms of generation, coal-fired power plants contributed 59% to the electricity generated in-state in 2019, again followed by natural gas (31%), and wind (6%). On the

demand side, which captures generation from power plants located both in-state and out-of-state, electricity stemmed primarily from coal (54%) and natural gas (28%) in 2019, in line with figures presented for in-state generation, but also from nuclear (10%), which was generated by I&M's Cook nuclear plant in Michigan.

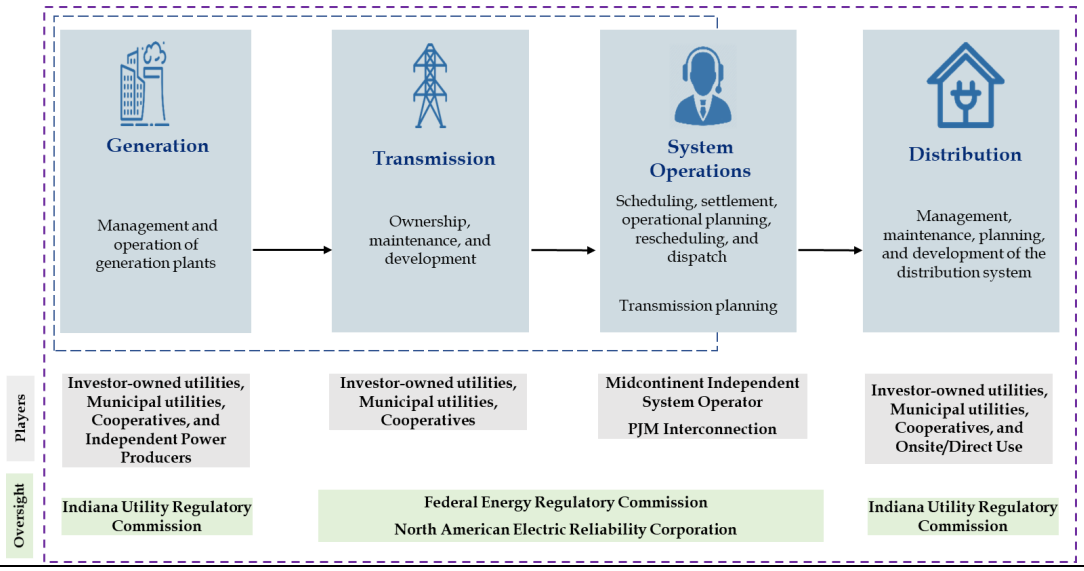
5.2 Industry structure

The electricity sector in Indiana includes three types of utilities:

1. **IOUs**, of which there are five: (i) Duke Energy Indiana ("Duke"), (ii) Indiana Michigan Power ("I&M"), (iii) Indianapolis Power & Light ("IPL"), (iv) Northern Indiana Public Service Company ("NIPSCO"), and (v) Vectren/CenterPoint Energy ("Vectren");
2. **munis**, of which there are 72, 60 of which are members of the Indiana Municipal Power Agency ("IMPA"). IMPA was formed by a group of munis to jointly operate and finance generation and transmission facilities. IMPA members deliver power to customers in their service territories stemming from a combination of "member-owned generating facilities, member-dedicated generation, and purchased power"; and
3. **REMCs** or **co-ops**, of which there are 38, which are customer-owned distribution utilities served by generation and transmission ("G&T") coops, Hoosier Energy, and Wabash Valley Power Association ("WVPA").

The industry structure is illustrated in Figure 37. Utilities and independent power producers ("IPPs") are members of either MISO or PJM, both nonprofit membership organizations, which as regional transmission organizations ("RTOs"), act as the system operators and market operators in the State. The Indiana Utility Regulatory Commission ("IURC"), as the State regulator, maintains a seat at MISO's Organization of the MISO States and PJM's Organization of PJM States, Inc. In the following subsections, LEI describes each segment of the electricity supply chain in the State and the institutions responsible for each segment.

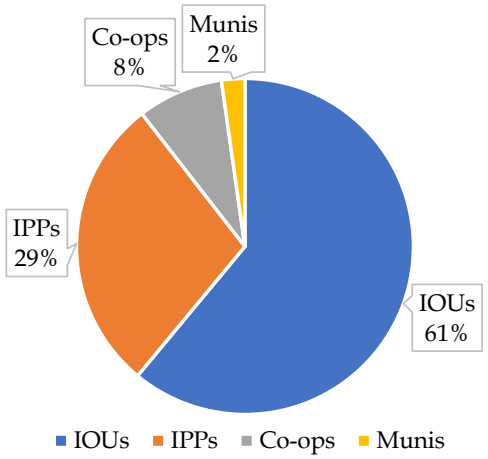
Figure 37. Electric industry structure in Indiana



5.2.1 Generation

Electric utilities (including IOUs, munis, and co-ops) account for 71% of all installed generation in Indiana, with IPPs owning the rest.[67] Figure 38 shows the breakdown of installed capacity by ownership type. Resources from outside of the State also make a contribution, including nuclear as well as purchases from wholesale markets.

Figure 38. Breakdown of installed generation by ownership type in Indiana



Source: Third-party commercial database (Accessed on July 17, 2020).

Coal-fired power plants continue to account for the majority of electricity generation, though they are rarely price-setting in wholesale markets. As demonstrated in Figure 39, coal's share of generation has decreased from 90% in 2010 to 59% by 2019. Despite this decline, Indiana is still among the top ten states in the nation relying on coal for electricity generation.[68] By 2019, Indiana's electricity generation mix was still dominated by coal, followed by natural gas (31%) and wind (6%) resources. Overall, total generation in Indiana has declined at a CAGR of -2.2% for the 2010-2019 period.

The relative changeover in generation resources has occurred more rapidly across the country; while states generally relied on coal (45%), natural gas (24%), and nuclear (20%) for electricity generation in 2010, by 2019, natural gas (38%) overtook coal (23%) in the national average generation mix. The decline in coal's share of generation over the past decade has occurred due to numerous coal retirements; in Indiana, this has amounted to 3,894 MW of retired coal capacity over the 2010-2018 period.[69] This downward trend in the share of coal is expected to continue, largely motivated by aging plants and declining cost competitiveness. Utilities in Indiana have

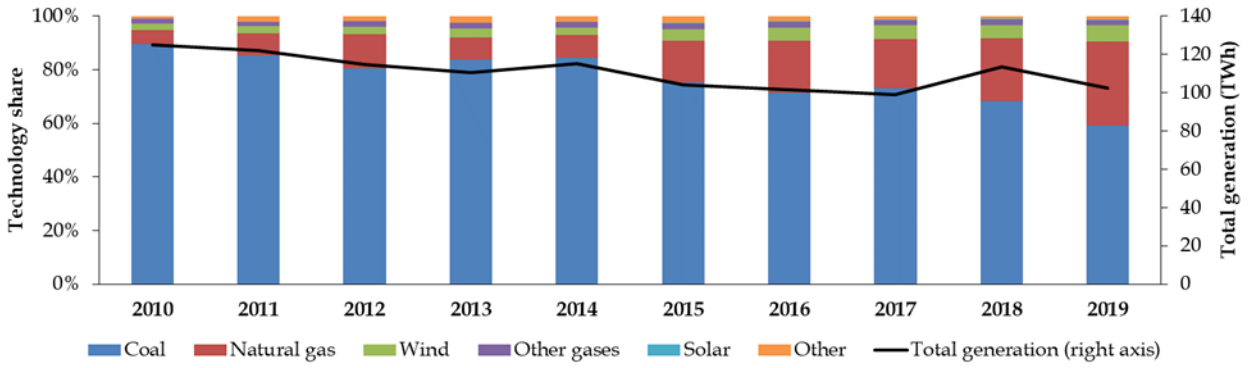
[67] US EIA. *Form EIA-861, Annual Electric Power Industry Report*. January 2019.

[68] Ibid.

[69] Indiana Utility Regulatory Commission. *2019 Annual Report*. 2019.

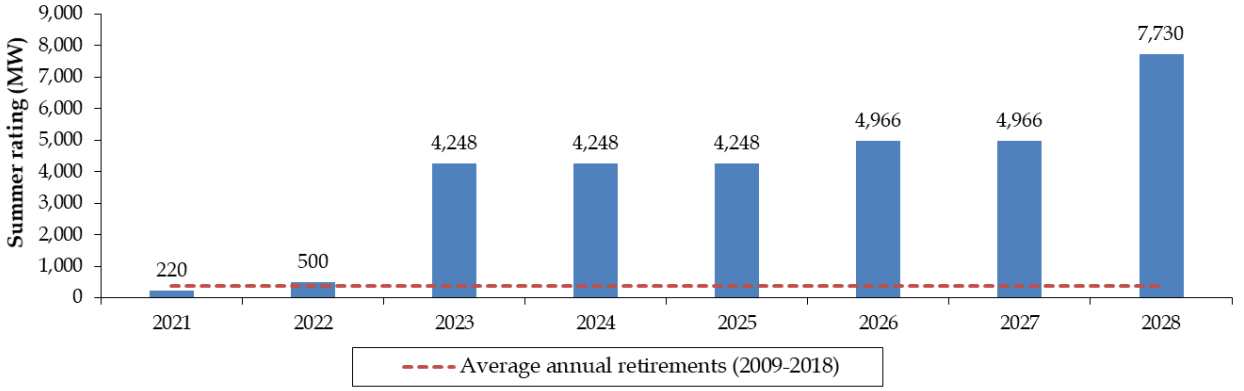
announced plans to retire as much as 7,730 MW of coal by 2028 (or 29% of 2019 total installed summer capacity for all resources) – see Figure 40.[70]

Figure 39. Electric generation in Indiana (2010-2019)



Source: US EIA. *Net Generation by State by Type of Producer by Energy Source*. 2020.

Figure 40. Cumulative planned coal retirements in Indiana, 2021-2028



Source: IURC. *2019 Annual Report*. 2019; IURC. *2020 Report to the 21st Century Energy Policy Development Task Force*. August 14, 2020.

As the share of coal has declined over the past decade, the shares of generation from natural gas-fired power plants and wind facilities have risen. Natural gas-fired generation has increased at a CAGR of 19.4%, from 5% in 2010 to 31% by 2019, and its share may continue to increase. This move away from coal and towards natural gas-fired power has been driven in part by technological advancements in natural gas drilling over the period (e.g., hydraulic fracking), which has helped to bring down costs and improve the commercial viability of natural gas.[71]

Similarly, wind generation has increased at a CAGR of 8.7%, from 2% in 2010 to 6% by 2019. Wind generation has grown every year since 2008, when Indiana's first utility-scale wind project, the

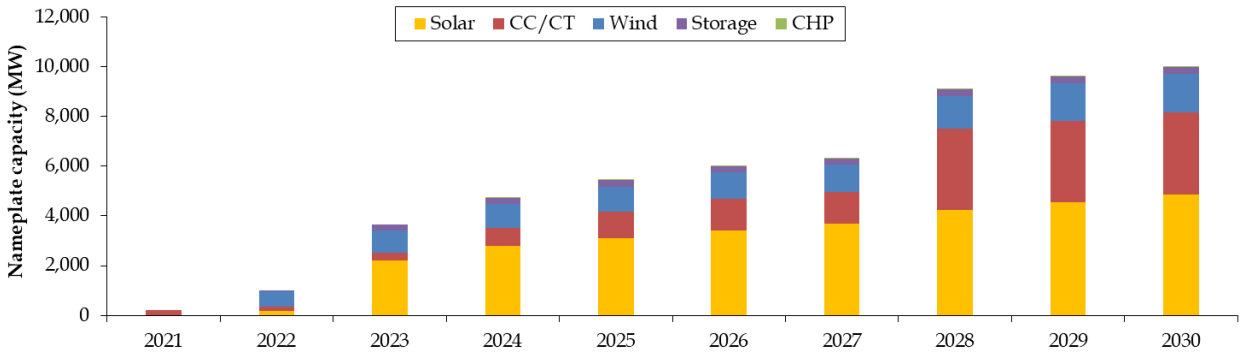
[70] IURC. *2020 Report to the 21st Century Energy Policy Development Task Force*. August 14, 2020.

[71] Indiana University. *The Long View: Indiana's Energy Outlook*. Winter 2015.

103.5 MW Benton County Wind Farm, came online.[72] Other renewables, such as solar, biomass, and hydro, currently account for around 1% of annual generation.[73]

The share of renewables is expected to continue to grow over the long-term, as indicated by the preferred portfolios outlined by utilities in their recent integrated resource plans ("IRPs"). These plans anticipate adding around 1.6 GW of wind and 4.8 GW of solar installations by 2030.[74] Figure 41 illustrates these planned resource additions, including around 3.3 GW of natural gas-fired generation.

Figure 41. Cumulative planned resource additions, 2021-2030



Note: Includes I&M's preferred portfolio, which incorporates additions in both Indiana and Michigan. Natural gas additions are represented by the CC/CT bar (combined-cycle ("CC") gas plant/combustion turbine ("CT")). CHP refers to combined heat and power systems.

Sources: IURC. *2020 Report to the 21st Century Energy Policy Development Task Force.* August 14, 2020; various utility IRPs.

In terms of other generation technologies, there are no nuclear power reactors operating in the State of Indiana.[75] However, 65% of the power generated at I&M's Cook nuclear plant (located in Michigan) serves retail customers in Indiana. As a result, nuclear is an important part of the State's electricity supply mix, as discussed in Section 4.6.

Generally, the average age of plants in Indiana is around 31 years (weighted based on installed capacity), as illustrated in Figure 42. Coal and hydro plants tend to be the oldest facilities in Indiana, with average ages of 42 and 62 years, respectively, while renewable plants are relatively newer, with an average age of seven years for wind and four for solar. The chart also demonstrates the capacity-weighted average age at retirement for fossil-fueled plants across the US, which as of 2018, averaged 44 years for oil, 41 years for coal, and 37 years for gas.

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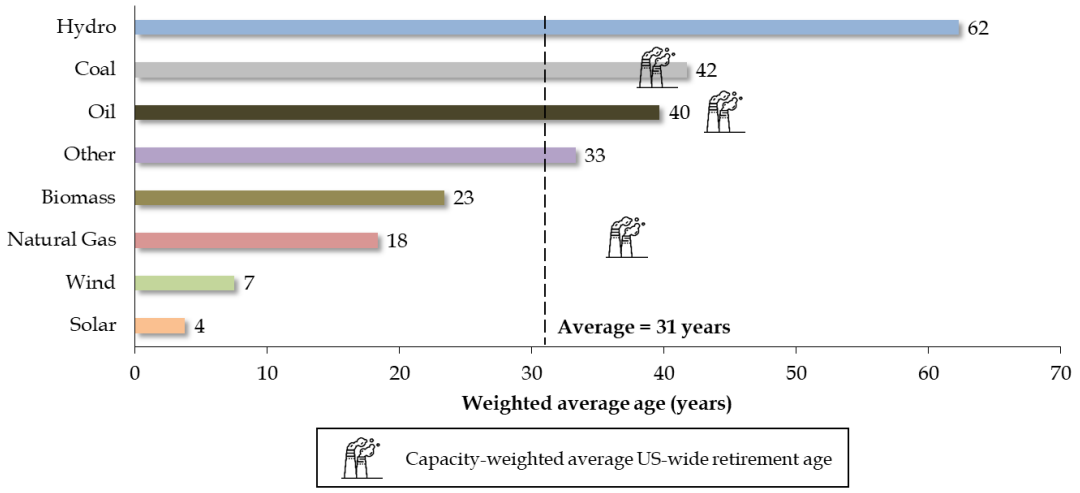
[72] US EIA. *Indiana State Energy Profile.* June 18, 2020.

[73] Ibid.

[74] IURC. *2020 Report to the 21st Century Energy Policy Development Task Force.* August 14, 2020; various utility IRPs.

[75] US Nuclear Regulatory Commission. *Indiana.* <https://www.nrc.gov/info-finder/region-state/indiana.html>

Figure 42. Capacity-weighted average age of generation assets in Indiana



Source: Third-party commercial database; S&P Global Market Intelligence. *Average age of US power plant fleet flat for 4th-straight year in 2018.* January 16, 2019.

5.2.2 Transmission and system operation

In Indiana, a transmission line is defined as a power line that is used for the transfer of electricity at 100 kilovolts or more.[76] There are over 13,000 miles[77] of transmission lines in Indiana, which are owned by the IOUs, Wabash Valley Power Association, Hoosier Energy, and munis, but they are managed and flows are controlled by either MISO or PJM. Figure 43 provides a breakdown of transmission lines by ownership type.

As mentioned earlier, MISO and PJM are RTOs, which are independent, nonprofit organizations that operate the bulk electric power systems in the region. RTOs serve a region of sufficient scope and configuration, enabling them to ensure reliability and perform their required functions.[78] They also have exclusive authority for maintaining the short-term reliability of the grid.[79] They are formed to meet the Federal Energy Regulatory Commission's ("FERC") requirements to ensure reliability and optimize supply and demand bids for wholesale electric power. FERC regulates and protects the reliability of the interstate transmission system through mandatory reliability standards. The North American Electric Reliability Corporation ("NERC") is the electric reliability organization for North America, responsible for developing and enforcing these reliability standards.[80] NERC is subject to FERC oversight. Figure 44 shows the minimum characteristics and functions of an RTO.

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[76] Indiana Code §§ 8-1-38-1.

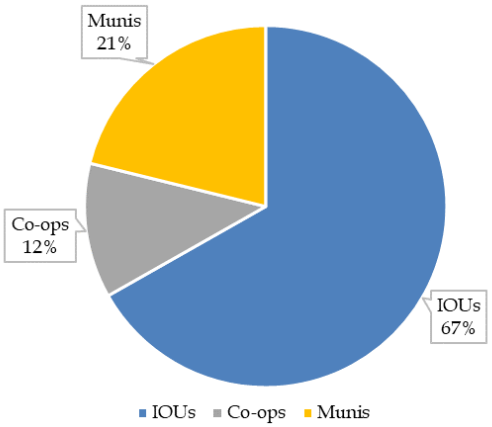
[77] US DOE. *State of Indiana: Energy Sector Risk Profile.* 2016.

[78] FERC. *FERC Order No. 2000.* 89 FERC ¶ 61,201. February 25, 2020. P. 46.

[79] Ibid. P. 47.

[80] NERC. *About NERC.* <https://www.nerc.com/AboutNERC/Pages/default.aspx>

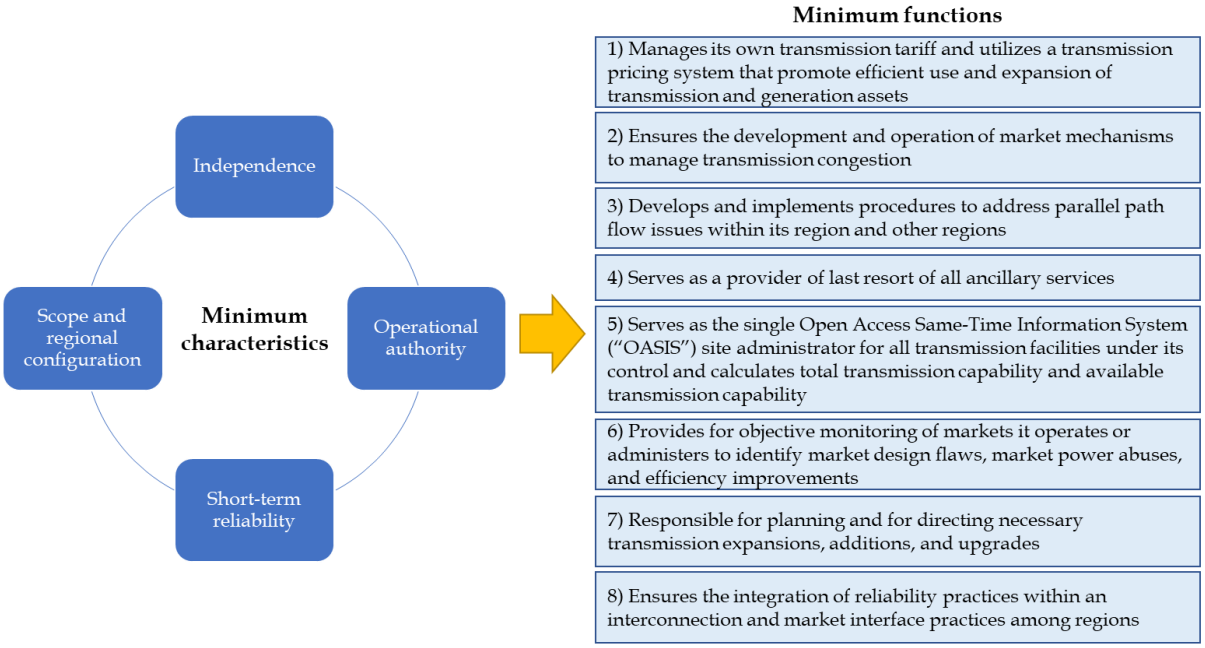
Figure 43. Breakdown of transmission lines by ownership type in Indiana



Note: IOU transmission line data as reported in FERC Form 1 filings; muni transmission line data comprises of the Joint Transmission System ("JTS"), which is jointly owned by IMPA, Duke Energy, and WVPA and provides transmission access to over 65% of Indiana; co-op data for Hoosier Energy only.

Sources: Third-party commercial database; Hoosier Energy. *About*; IMPA. *Transmission.*

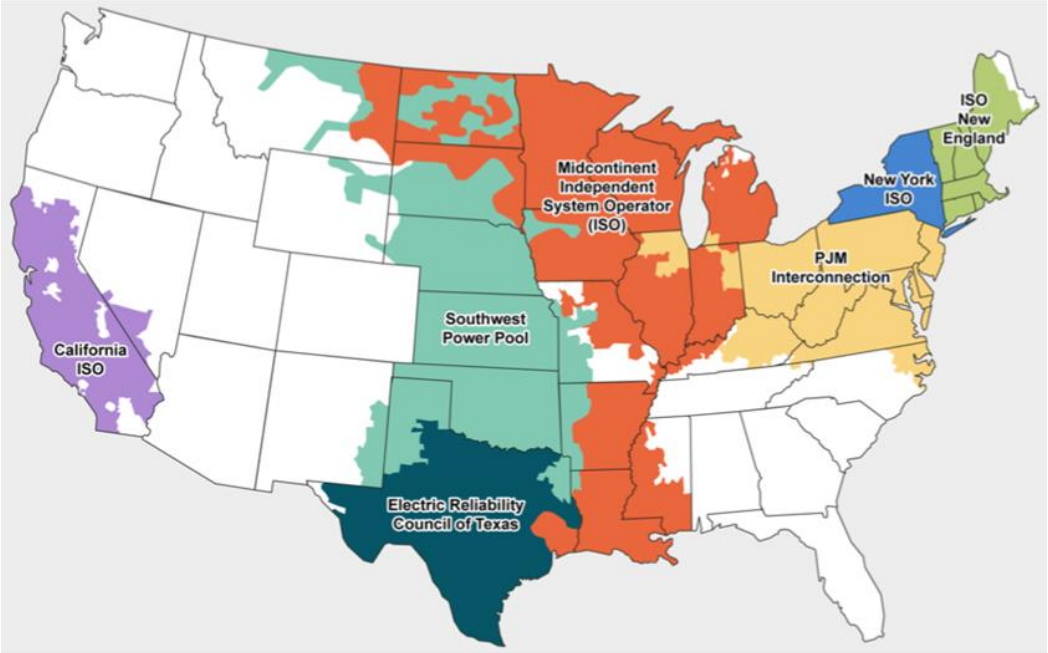
Figure 44. Minimum characteristics and functions of an RTO



Source: FERC Order 2000.

Duke, NIPSCO, IPL, Vectren, American Electric Power ("AEP"), Hoosier Energy, IMPA, and WVPA participate in MISO, while AEP (including its Indiana subsidiary, I&M), IMPA, and WVPA participate in PJM. An overview of PJM and MISO is provided in the textbox below, while Figure 45 shows a map of their footprints (PJM in yellow, MISO in orange) and lists the participating utilities in PJM and MISO.

Figure 45. Map of US ISOs and Indiana utilities participating in MISO and PJM



Characteristics	MISO	PJM
Participating Indiana utilities	Duke, NIPSCO, IPL, Vectren, AEP, Hoosier Energy, IMPA, and WVPA	AEP *(including its Indiana subsidiary I&M)*, IMPA, and WVPA
Transmission lines (across footprint)	71,800 miles	84,236 miles
Generation capacity (across footprint)	175,528 MW	180,086 MW
Annual billings	$29.9 billion	$49.8 billion
Headquarters	Carmel, Indiana	Audubon, Pennsylvania

Sources: Indiana Office of Utility Consumer Counselor ("OUCC"), MISO Corporate Information, and PJM website.

MISO

The Midcontinent Independent System Operator ("MISO"), previously known as Midwest ISO, was established in 1998 as an ISO after FERC accepted its organizational plan and initial transmission tariff. In FERC's Order 2000, issued on December 20, 1999, FERC suggested all public utilities that own, operate, or control interstate electric transmission should form or join an RTO by December 15, 2001. On December 20, 2001, MISO became a FERC-approved RTO. Since then, MISO has fostered wholesale electric competition in the region, created greater system reliability, and established coordinated, value-based regional planning. *continued…*

MISO has grown to include 52 Transmission Owners and 137 Non-Transmission Owners. Today, the MISO market footprint covers 71,800 miles of transmission lines carrying 177,760 MW of power annually, serving about 42 million people. MISO manages one of the world's largest energy and operating reserves markets using security-constrained economic dispatch of generation. The Energy and Operating Reserves Market includes a Day-Ahead Market, a Real-Time Market, a Financial Transmission Rights Market, all of which are operated and settled separately.

MISO delivers electric power across 15 states, including all or part of Arkansas, Illinois, Indiana, Iowa, Kentucky, Louisiana, Michigan, Minnesota, Mississippi, Missouri, Montana, North Dakota, South Dakota, Texas, and Wisconsin and the Canadian province of Manitoba. LEI models MISO with 3 subregions based on historical transmission constraints; Indiana is part of MISO Central. MISO operates one of the world's largest energy markets with more than $29 billion in annual gross market energy transactions.

Sources: MISO Corporate Information, MISO Facts.

PJM

PJM Interconnection coordinates the movement of wholesale electricity in 13 states (parts or all of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, and West Virginia) and the District of Columbia. PJM began in 1927 with three utilities in its namesake states (Pennsylvania, New Jersey, and Maryland). In 1993, PJM started the transition to an independent, neutral organization when the PJM Interconnection Association was established to administer the power pool. PJM became a fully independent organization in 1997.

PJM operates North America's largest power grid, with a market footprint covering approximately 84,200 miles of transmission lines. PJM has an annual generation capacity of over 180,000 MW, serving around 65 million people. Currently, PJM administers a $49.8 billion annual competitive wholesale electricity market with more than 1,000 participants buying and selling electric energy, capacity, ancillary services, and transmission rights. PJM plans regional transmission expansion improvements to maintain grid reliability and relieve congestion. PJM has twenty transmission zones, where Indiana is part of the AEP zone.

Sources: PJM Fast Facts, and PJM website.

5.2.3 Distribution

A distribution line is defined as a power line that is used for the transfer of electricity below 100 kilovolts. The distribution lines are owned, operated, and maintained by IOUs, REMCs, and munis within their exclusive service territory. Figure 46 provides a breakdown of distribution circuits by ownership type; notably, due to limited data availability, this breakdown is provided in terms of number of distribution circuits, as opposed to distribution line mileage, as utilities report the former and not the latter to the US EIA.

Separately, Figure 47 breaks down the share of customers in Indiana by ownership type. IOUs serve approximately 75% of customers in the State, followed by co-ops (18%), and munis (8%).

Figure 46. Breakdown of distribution lines by ownership type in Indiana

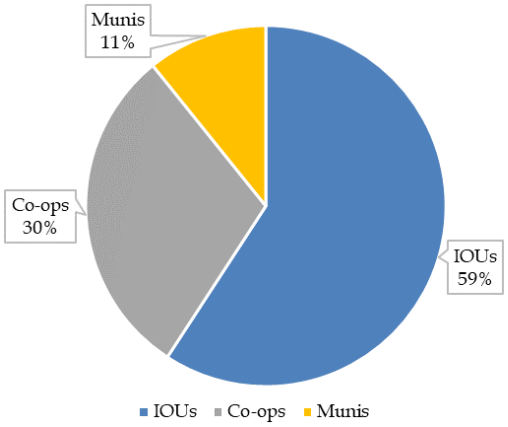
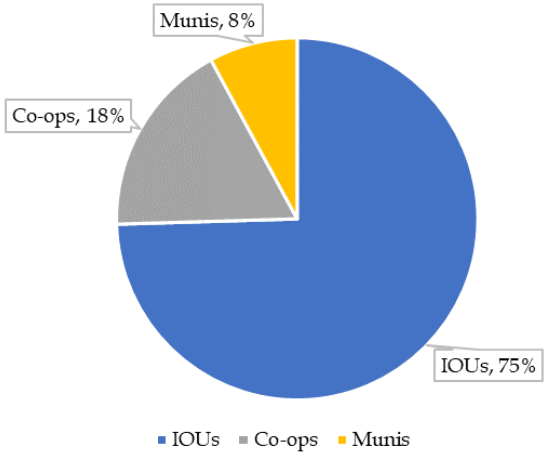


Figure 47. Share of customers by ownership type in Indiana (2019)

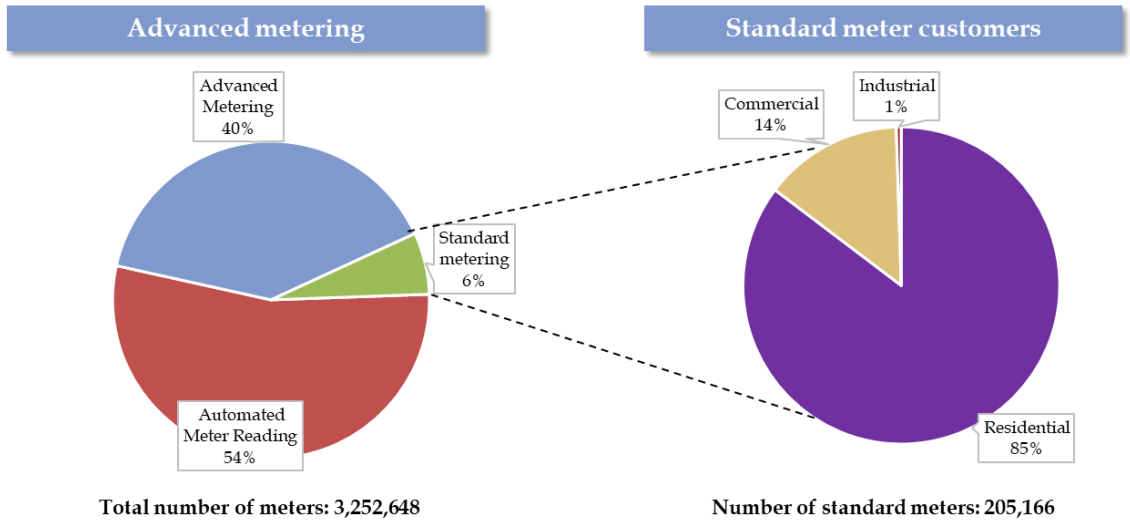


Source: US EIA. *Form EIA-861, Annual Electric Power Industry Report.* January 2019.

In terms of other distribution assets, most meters in the State are classified under three categories, namely, advanced meter infrastructure ("AMI"), automatic meter reading ("AMR"), or standard metering, which correspond to 54%, 40%, and 6% of all meters, respectively. While most customers use advanced metering, residential customers account for approximately 85% of customers with standard meters (Figure 48).[81]

[81] US Energy Information Administration. *Form EIA-861, Annual Electric Power Industry Report*. Accessed on July 27, 2020.

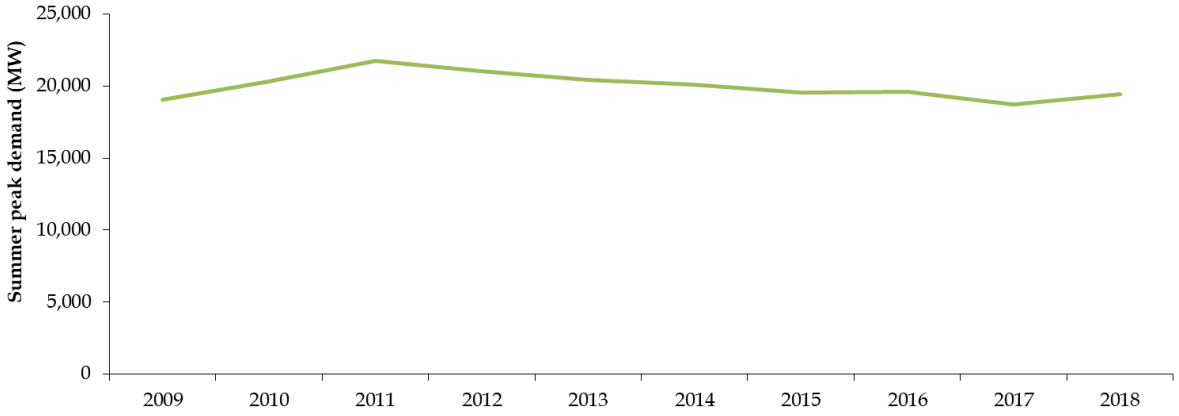
Figure 48. Advanced meter penetration among Indiana customers



Source: US Energy Information Administration. *Form EIA-861, Annual Electric Power Industry Report*. January 2019.

Historical electricity demand in Indiana is expressed in both peak demand and electricity sales. Peak demand is the maximum amount of electricity consumed at any point in a year, denominated in MW. In Indiana, historical peak demand has been relatively flat over the past decade, growing at a CAGR of 0.2% over the 2009 to 2018 period, as illustrated in Figure 49. Notably, Indiana has been a net importer of electricity since 2012, consuming more power than is produced by in-state generators.[82] In 2018, Indiana imported 3% of electricity from out-of-state resources to meet demand.[83]

Figure 49. Historical peak demand in Indiana (2009-2018)



Source: SUFG for the IURC. *Indiana Electricity Projections: The 2019 Forecast*. November 2019.

[82] US EIA. *Indiana State Energy Profile*. June 18, 2020.

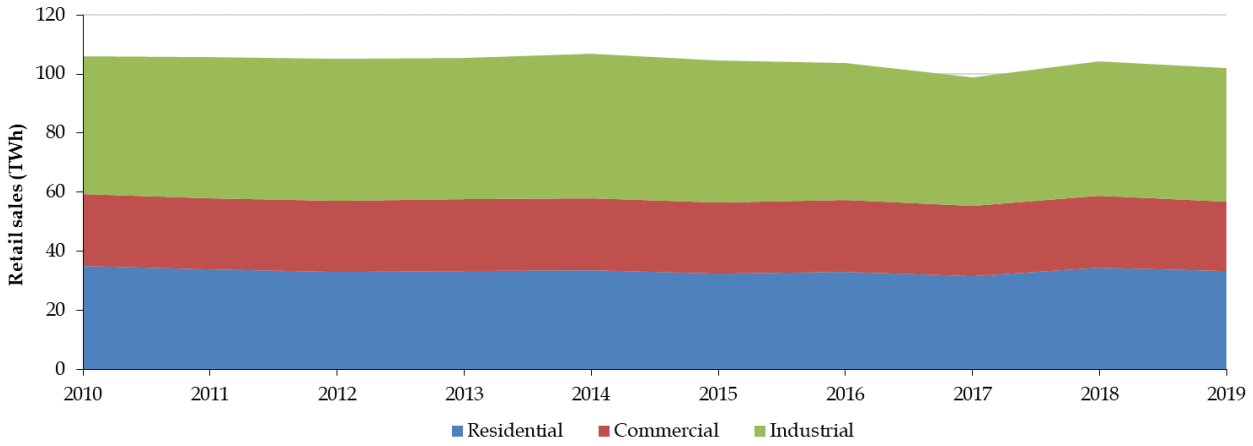
[83] Ibid.

The flat demand trend is likely to continue going forward, due to continued energy efficiency efforts and declining energy intensity per customer, with peak electricity demand projected to grow at a CAGR of 0.6% over the next 20 years.[84] This equates to approximately 125 MW in increased peak demand per year; as such, it is expected that significant investments in additional resources will not be needed until 2024.[85] Given the interconnected nature of electricity markets, these additions need not necessarily be in Indiana.

Demand, sometimes referred to as load, consumption, or sales, is the total amount consumed in a year, denominated in terawatt-hours ("TWh"). Electricity sales among various customer classes have also flattened over the past ten years, with load declining at a CAGR of -0.4% (2010-2019). Load growth over the 2010 to 2019 period has been lowest among residential customers (CAGR of -0.6%), followed by commercial customers (CAGR of -0.4%), and industrial customers (CAGR of -0.3%), as depicted in Figure 50.

As of 2019, industrial customers accounted for 44% of load, followed by residential (33%) and commercial (23%) customers. Relative to the national average, Indiana's customer mix is substantially more skewed towards industrial customers; across the US, the average customer mix comprised 38% residential, 36% commercial, and 26% industrial customers in 2019.[86]

Figure 50. Retail sales in Indiana by customer class (2010-2019)



Source: US EIA. *Retail Sales of Electricity by State by Sector by Provider, Form EIA-861, Detailed State Data.* 2020.

This trend in flattening load growth has been driven by numerous factors, including rising electricity prices (affecting all customer classes), increasing energy efficiency efforts, declining intensity of electricity use (commercial), and more modest manufacturing output (industrial).[87] As these factors continue to impact customers, electricity usage is forecast to grow slightly at 0.7%

[84] SUFG for the IURC. *Indiana Electricity Projections: The 2019 Forecast.* November 2019.

[85] Ibid.

[86] US EIA. *Retail Sales of Electricity by State by Sector by Provider, Form EIA-861, Detailed State Data.* October 22, 2019.

[87] SUFG for the IURC. *Indiana Electricity Projections: The 2019 Forecast.* November 2019.

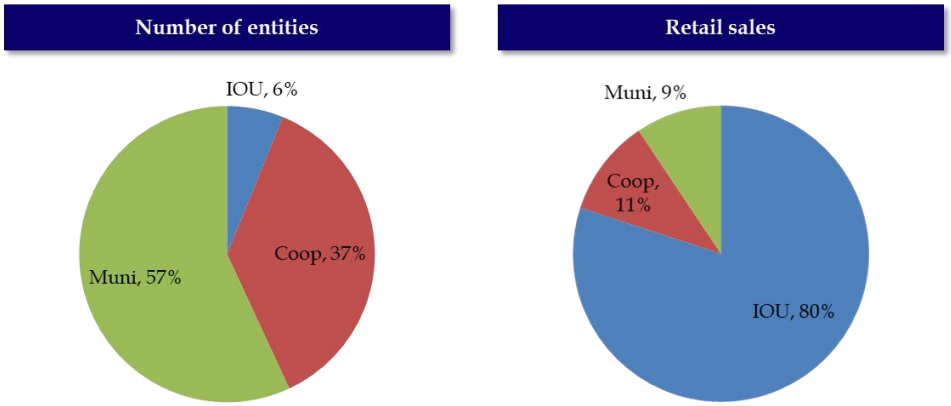
per year over the next 20 years (with projected CAGRs of -0.1% for commercial, 0.45% for residential, and 1.26% for industrial customers).[88]

Notably, these forecasts do not factor in the impacts from the ongoing COVID-19 pandemic, which may lead to changes in not only the demand patterns across customer classes, but also overall load levels, where there is particular uncertainty about the extent and permanency of demand destruction. Uncertainties around the impact of COVID-19 on load are discussed in Section 9.7.

5.2.4 Market participants

As mentioned in Section 5.2, numerous IOUs, munis, and REMCs serve retail customers in Indiana. In 2019, the five IOUs in the State accounted for 80% of total electricity sales, compared to munis and REMCs, which accounted for 9% and 11% of sales, respectively (Figure 51). The following section provides an overview of the market players responsible for serving the majority of customers in Indiana (Figure 52 summarizes various metrics for each type of service provider).

Figure 51. Number of entities and share of retail sales by ownership type in Indiana (2019)



Source: US EIA. *Class of ownership, number of consumers, sales, revenue, and average retail price by State and utility, Form EIA-861, Electricity Sales, Revenue, and Average Prices.* 2020.

Figure 52. Summary of key statistics by service provider in Indiana (2019)

Service provider	No. of entities	Total sales (2019)	Average number of customers (2019)	Percentage of distribution circuits (2019)
IOUs	5	80%	486,000	59%
REMCs	38	11%	15,000	30%
Munis	72	9%	4,000	11%

Sources: EIA, IURC, Indiana Electric Cooperatives

[88] Ibid.

5.2.4.1 IOUs

IOUs use a form of ownership in which a utility is owned by shareholders and operated to generate profit. An IOU can be publicly traded or privately held. In the case of Indiana, all IOUs are publicly listed through their parent holding companies. Below is a brief description of these five IOUs; Figure 53 shows the service territories for IOUs, co-ops, and munis in Indiana.

- **Duke** is a subsidiary of Duke Energy Corporation. Covering 22,000 square miles of service area, it provides electric utility service to more than 840,000 customers located in 69 of Indiana's 92 counties, spread across north-central, central, and southern Indiana.[89] Duke also sells electricity for resale to munis, Wabash Valley Power Association, Inc., Indiana Municipal Power Agency, Hoosier Energy, and other electric utilities that, in turn, supply electric utility service to customers in areas that are not served by Duke.
- **I&M** is a subsidiary of AEP. It supplies electric energy to around 468,000 retail customers in the northern and eastern-central part of the State. [90,91] It serves the following counties: Adams, Allen, Blackford, DeKalb, Delaware, Elkhart, Grant, Hamilton, Henry, Howard, Huntington, Jay, LaPorte, Madison, Marshall, Miami, Noble, Randolph, St. Joseph, Steuben, Tipton, Wabash, Wells, and Whitley.[92]
- **IPL**, a subsidiary of AES Corporation, supplies electricity to approximately 500,000 retail customers in and near the City of Indianapolis and in parts of Boone, Hamilton, Hancock, Hendricks, Johnson, Marion, Morgan, Owen, Putnam, and Shelby counties.[93]
- **NIPSCO**, a subsidiary of NiSource Inc. (headquartered in Merrillville, Indiana), supplies electric energy to more than 460,000 customers located in Northern Indiana, namely, all or parts of Benton, Carroll, DeKalb, Elkhart, Fulton, Jasper, Kosciusko, LaGrange, Lake, LaPorte, Marshall, Newton, Noble, Porter, Pulaski, St. Joseph, Starke, Steuben, Warren and White Counties in northern Indiana.[94]
- **Vectren**, a CenterPoint Energy subsidiary, provides electric service to more than 146,000 electric consumers in southwestern Indiana.[95] Its service territory includes Pike, Gibson, Dubois, Posey, Vanderburgh, Warrick, and Spencer counties.

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[89] Duke Energy Indiana. *2018 Integrated Resource Plan: Volume I.* July 1, 2019.

[90] Indiana Michigan Power. *Integrated Resource Planning: Public Summary.* July 1, 2019.

[91] Indiana Utility Regulatory Commission. *2019 Annual Report.* 2019.

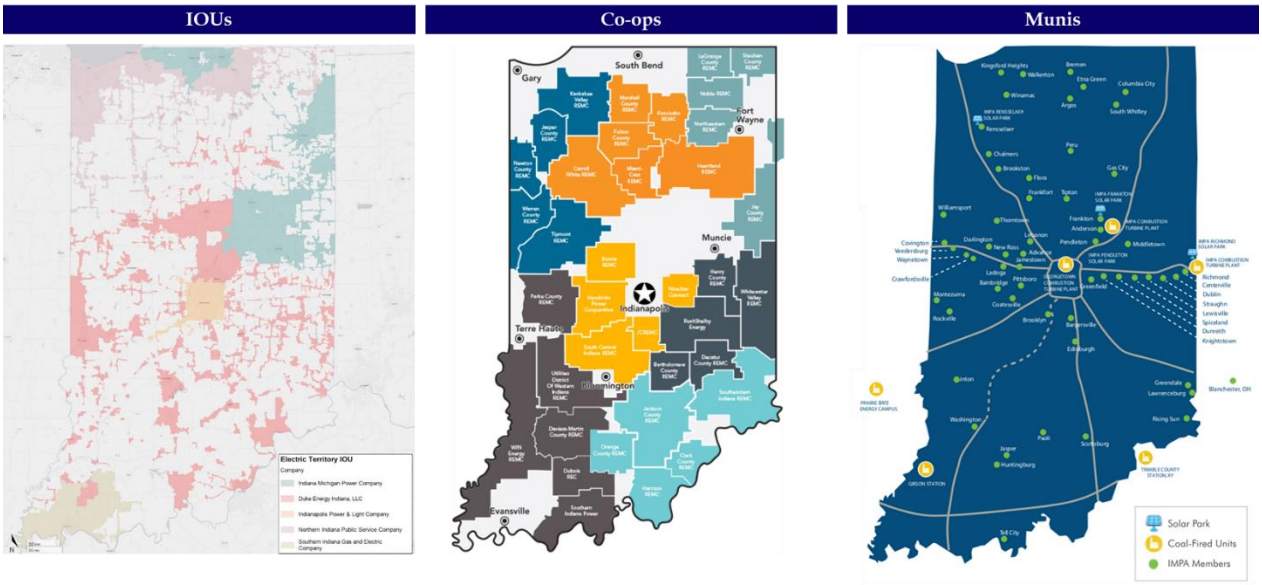
[92] Ibid.

[93] Indianapolis Power & Light Company. *2019 Integrated Resource Plan: Volume 1 of 3.* December 16, 2019.

[94] Northern Indiana Public Service Company LLC. *2018 Integrated Resource Plan.* October 31, 2018.

[95] Vectren. *2019/2020 Integrated Resource Plan: Non-Technical Summary.* June 2020.

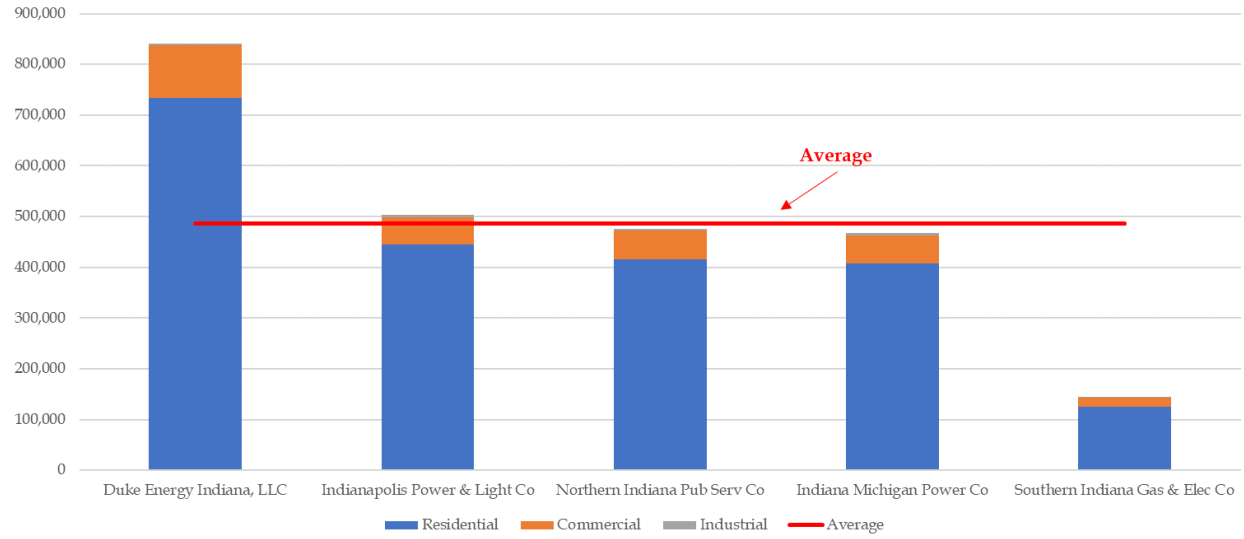
Figure 53. Maps of service territories by service provider in Indiana



Source: Third-party commercial database; Indiana Electric Cooperatives; IURC.

Duke is the largest IOU in terms of number of customers served (Figure 54), followed by IPL, NIPSCO, I&M, and Vectren. Based on EIA data, IOUs in the State in 2019 served an average of 486,000 customers.

Figure 54. Number of customers served by the IOUs in Indiana (2019)



Source: US Energy Information Administration. *Form EIA-861, Annual Electric Power Industry Report*. 2020.

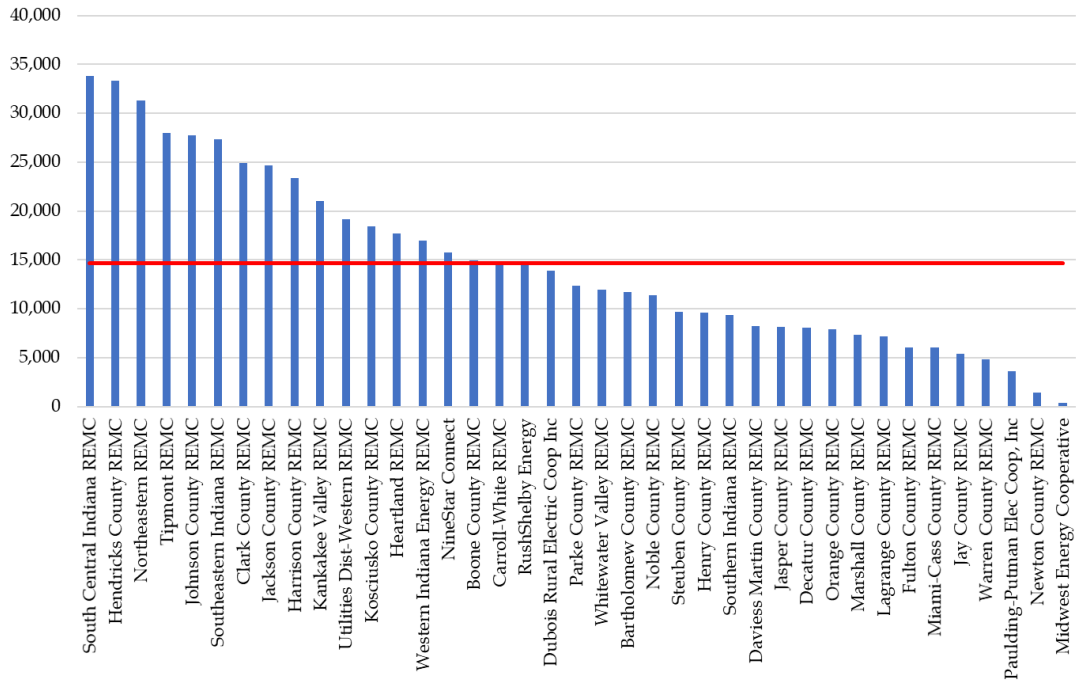
IOU management reports to a board of directors, which has a fiduciary duty to its shareholders. Management, in turn, responds to signals from its regulators regarding priorities. Generally, IOUs are required to provide reliable service, consistent with good utility practice, by making

prudent investments. They are entitled to a fair return on their regulated asset base provided they have done so consistently with prevailing regulations. IOUs in the State are required to obtain IURC's approval for any rate adjustments they wish to implement.

5.2.4.2 REMCs

REMCs or co-ops are member-owned utilities that are legally established to serve the service territory of its members. The Indiana Electric Cooperatives ("IEC"), which is an electric co-op service organization serving co-ops across 89 counties, has 38 REMC members.[96] Electric co-ops can either be (i) generation and transmission ("G&T") co-ops, (ii) distribution co-ops, or (iii) both. G&T co-ops provide wholesale power to distribution co-ops through their own generation, or by purchasing power on behalf of the distribution members, while distribution co-ops deliver electricity to their customers.

Figure 55. Number of customers served by individual co-ops in Indiana (2019)



Source: US Energy Information Administration. *Form EIA-861, Annual Electric Power Industry Report*. 2020.

Indiana is served by 38 retail co-ops, which are responsible for 11% of all retail sales in the State and provided electricity to 572,040 customers in 2019.[97] As mentioned earlier, there are two G&T co-ops in the State: WVPA and Hoosier Energy. WVPA serves the 19 distribution co-ops of northern and central Indiana (plus three co-ops in Illinois and one in Missouri),[98] while Hoosier

[96] Indiana Electric Cooperatives. *Who We Are.* <https://www.indianaec.org/who-we-are/>

[97] EIA.

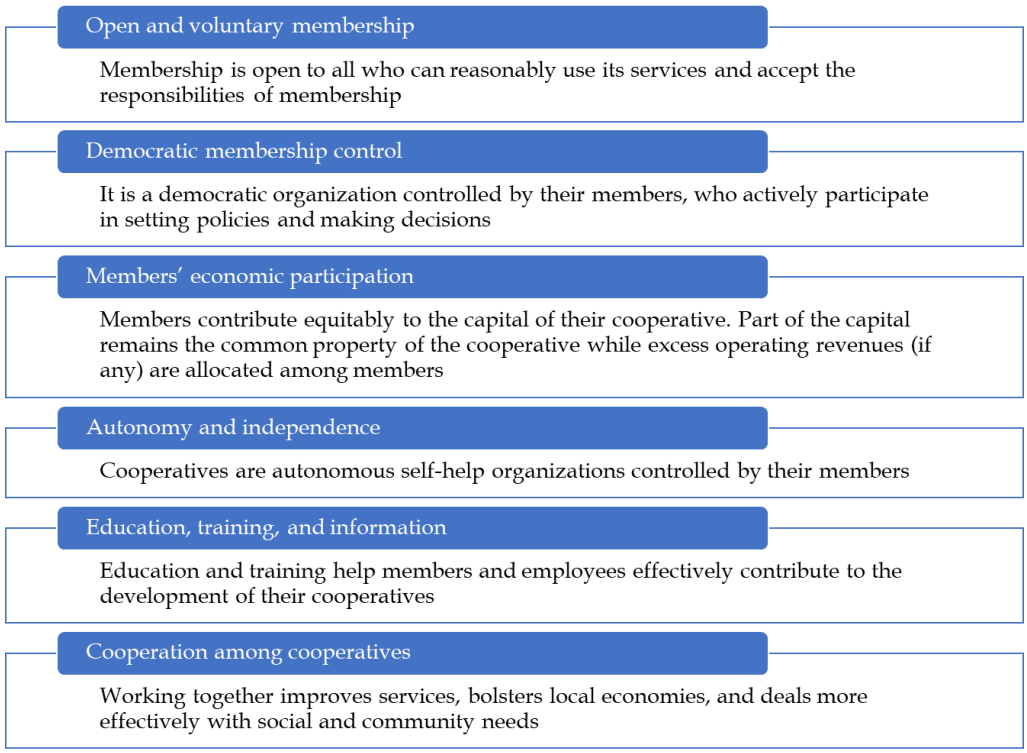
[98] Wabash Valley Power Alliance. *Who We Are.* Accessed on July 27, 2020.

Energy serves 18 distribution co-ops in central and southern Indiana and southeastern Illinois (see Figure 53 for the service territory map of these REMCs). Based on EIA data, REMCs in Indiana in 2019 served an average of 15,000 customers. An illustration of the number of customers served by Indiana co-ops is illustrated in Figure 55.

REMCs in the US operate according to the same set of core principles adopted by the International Co-operative Alliance (Figure 56). Co-ops are democratically controlled by their members and governed by a board of directors. Therefore, they are autonomous and independent. Generally, co-op members have equal voting rights (one member, one vote basis). Some of the responsibilities of the board include, but are not limited to:

- setting major policies and procedures that are implemented by the co-op's management;
- advocating for their members;
- approving annual operating budgets, capex budgets, and compensation plans;
- recruiting and selecting a CEO; and
- choosing an independent auditor for the annual financial audit.

Figure 56. Co-op principles

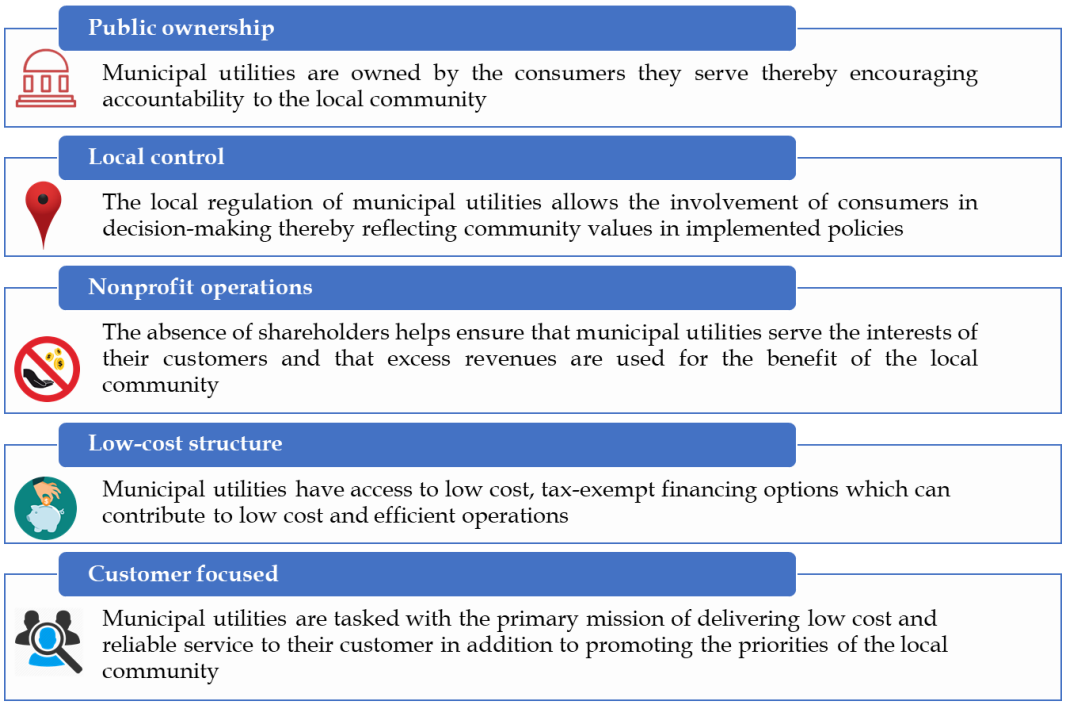


Source: National Rural Electric Cooperative Association.

5.2.4.3 Municipal utilities

Munis are generally owned by cities and towns. Many municipal utilities arose out of public works departments in cities and towns; over time, these assumed a separate corporate identity from the cities that own them and that they serve. Key attributes of municipal utilities include public ownership, local control, non-profit operations, low-cost structure, and a customer focus (Figure 57).

Figure 57. Key attributes of munis

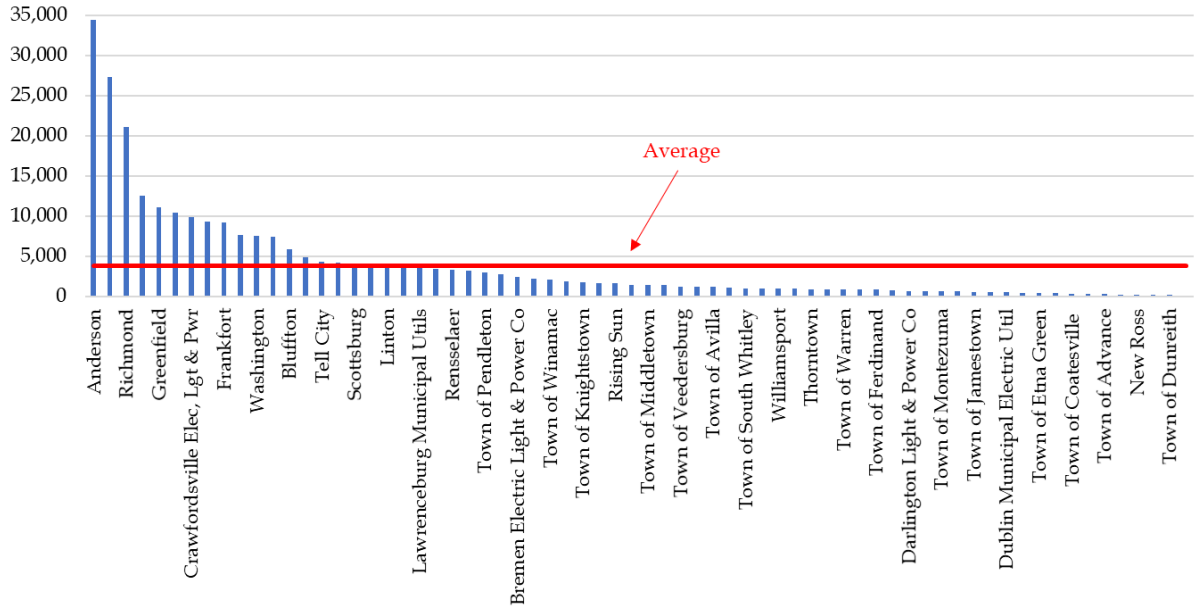


Source: American Public Power Association. *Public Power for Your Community*. 2016.

Indiana has 72 munis managed by local municipalities, 60 of which are members of IMPA.[99] As mentioned earlier, IMPA was created by a group of munis to fund and operate generation and transmission facilities jointly. IMPA members provide service to over 330,000 individuals throughout Indiana (and Ohio). Based on the munis that submit their information to the EIA, the average number of customers served by munis in Indiana is approximately 4,000. Figure 58 shows the number of customers served by munis in 2019, while Figure 53 illustrates the service territories of these munis.

[99] American Public Power Association. *Public Power in Indiana*. <https://www.publicpower.org/public-power-indiana>

Figure 58. Number of customers served by munis in Indiana (2019)



Note: Only 68 of the 72 munis in Indiana submit the EIA Form 861. Therefore, the bar chart only shows the numbers of those that have submitted it.

Source: US Energy Information Administration. *Form EIA-861, Annual Electric Power Industry Report*. January 2019.

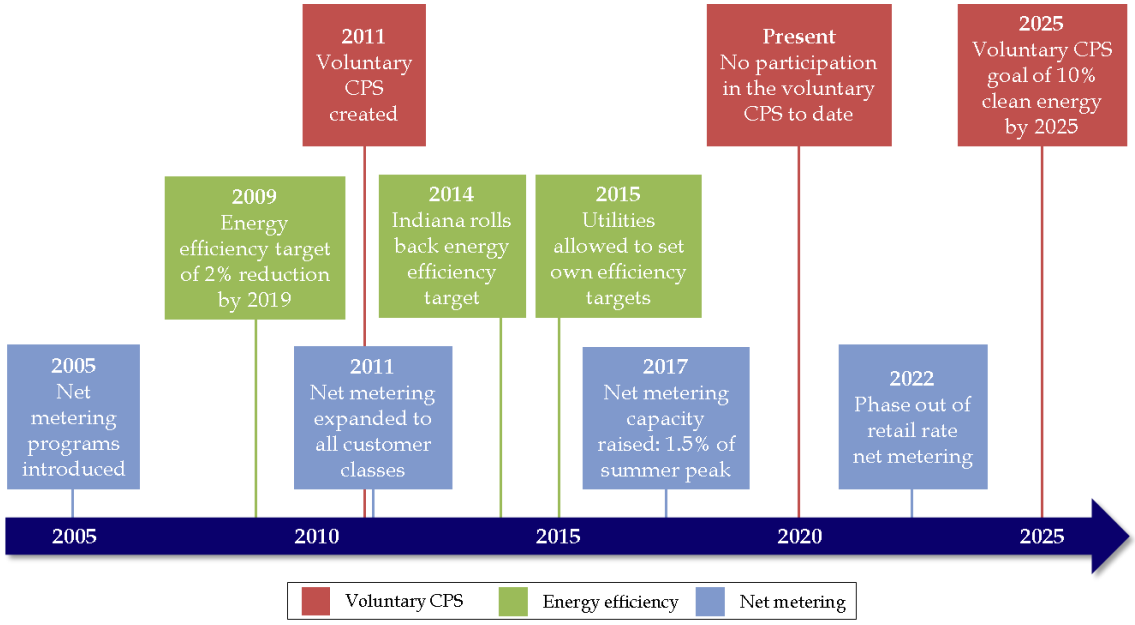
5.3 Relevant energy policies

The following section summarizes a selection of energy policies in the State of Indiana, including the voluntary Clean Energy Portfolio Standard ("CPS"), the history and current state of energy efficiency rules, and the extent of incentives for renewables deployment, including net metering and feed-in tariffs ("FITs"). A timeline of the implementation of these policies is illustrated in Figure 59. Notably, although a statewide energy plan has not been in effect since the release of the 2006 Strategic Energy Plan,[100] it is anticipated that the 21st Century Development Task Force (the "Task Force") will issue a report with recommendations to the General Assembly and Governor, among others, by the end of 2020.[101] The Task Force's statutory directive is discussed in further detail in Section 10.1.1.

[100] *Indiana's Strategic Energy Plan: Economic Growth from Hoosier Homegrown Energy*. 2006.

[101] 21st Century Energy Policy Development Task Force. *Information Report*. October 31, 2019.

Figure 59. Timeline of relevant state energy policies in Indiana



5.3.1 Renewable portfolio standard

In 2011, Indiana's legislature enacted Senate Bill 251, creating the voluntary CPS: the Comprehensive Hoosier Option to Incentivize Cleaner Energy ("CHOICE") program.[102] Therein, the State set a voluntary threshold whereby participating utilities agree to acquire 10% of their electricity from clean energy sources by 2025, relative to 2010 retail sales.[103]

> *"In order to ensure that the impact on the utility rates would be kept to a bare minimum, the Indiana General Assembly designed the Indiana CHOICE program to be voluntary. No utility in Indiana is required to join the program or will be specifically penalized for not joining the program."*
>
> Source: Indiana Office of Energy Development. *CHOICE Program FAQ*. <https://www.in.gov/oed/2650.htm>

The law sets out 21 clean energy sources that are eligible to count towards the 10% by 2025 goal, including renewables, but also conventional technologies such as nuclear, "clean coal," and natural gas that displaces electricity from coal.[104] Notably, these conventional technologies can contribute towards up to 30% of the goal.[105] In addition, at least 50% of the clean energy must be generated within Indiana.[106]

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[102] DSIRE. Clean Energy Portfolio Standard. Last updated June 18, 2018.

[103] State Utility Forecasting Group. *2019 Indiana Renewable Energy Resources Study*. September 2019.

[104] DSIRE. *Clean Energy Portfolio Standard.* Last updated June 18, 2018.

[105] Ibid.

[106] US EIA. *Indiana State Energy Profile.* June 18, 2020.

In return for participating in the voluntary CPS, utilities receive financial incentives (in the form of an up to 50 basis point adder on their return on equity),[107] which they can use to pay for compliance projects.[108] However, no utilities have sought to participate in the CHOICE program to date.[109] Despite this lack of participation, Indiana generated 6% of 2010 electricity sales from renewables (wind, solar, hydro) in 2019, suggesting the State is already halfway towards the voluntary threshold envisioned in the CHOICE bill.

5.3.2 Energy efficiency standard

In 2009, the IURC promulgated an energy efficiency target requiring the State's five IOUs to reach an overall 2% reduction in annual electricity sales by 2019 (where the reduction benchmark is based on average weather-normalized electric sales over the prior three-year period).[110] This target could be met through demand-side management ("DSM") programs such as demand response and energy efficiency.

Demand response: designed to shift the timing of energy consumption away from periods of peak demand.

Energy efficiency: designed to reduce energy consumption through equipment upgrades or behavioral change.

Source: IURC. *DSM and Energy Efficiency.* <https://www.in.gov/iurc/2802.htm>

In 2014, through State Enrolled Act 340, the General Assembly began examining the IURC's program over concerns around its overall expense.[111] This culminated in a rolling back of the State's energy efficiency target, making Indiana the first state in the nation to repeal its energy efficiency program.[112]

Through State Enrolled Act 412 (2015), utilities are now allowed to set their own efficiency targets.[113] All five IOUs offer energy efficiency programs, which must be approved by the IURC in energy efficiency plans submitted every three years.[114] These plans are assessed based on whether they are "reasonably achievable, consistent with the utility's integrated resource plan, and designed to achieve an optimal balance of energy resources in the utility's service territory."[115] Under the law, for plans that the IURC deems to be reasonable, utilities are able to

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[107] Indiana Utility Regulatory Commission. *Emergency Rulemaking: IURC RM #11-05.* December 21, 2011.

[108] State Utility Forecasting Group. *2019 Indiana Renewable Energy Resources Study.* September 2019.

[109] Indiana Utility Regulatory Commission. *2019 Annual Report.* 2019.

[110] Indiana Utility Regulatory Commission. *Cause No. 43693: Phase II Order.* December 9, 2009.

[111] Ibid.

[112] Utility Dive. *Indiana Cost Consumers $140M by Nixing Efficiency Program, AEC Says*. July 26, 2018.

[113] DSIRE. Electric Efficiency Standard. Last updated May 12, 2015.

[114] IURC Staff. *2018 Report on the Statewide Analysis of Future Resource Requirements for Electricity.* 2018.

[115] Ibid.

recover energy efficiency program costs, as well as lost revenues, and financial incentives[116] approved by the IURC.[117] Although the law does not require munis and REMCs to submit energy efficiency plans to the IURC for approval, Hoosier Energy, IMPA, and WVPA all offer DSM programs.[118]

5.3.3 Incentives for renewables

> **Feed-in tariff:** an incentive designed to encourage and accelerate renewable energy technology investments through providing long-term contracts to renewable energy producers.

Other incentives for renewables include net metering programs and feed-in tariffs ("FITs"). In 2005, net metering programs became effective in Indiana.[119] Under net metering, customers that install their own small scale renewable energy systems receive a kWh bill credit at the retail rate (applied to the following billing cycle and carrying over indefinitely)[120] for any excess generation produced and sold back to the grid. As of 2019, all five IOUs offer these programs, reporting nearly 91 MW of customer enrollment (92% solar, 7% wind, and around 0.3% biomass).[121]

In 2011, the IURC expanded the net metering program to all customer classes, provided their renewable energy systems are sized less than or equal to 1 MW.[122] Eligible technologies include wind, solar, hydro, fuel cells, hydrogen, organic waste biomass, and dedicated crops powered generation.

In 2017, through Senate Enrolled Act 309, the IURC further expanded the program by revising program capacity to 1.5% of a utility's summer peak load.[123] The legislation also called for the phasing out of retail rate net metering after June 30th, 2022, such that eligible installations applying for the program after this date receive compensation at a rate of 1.25 times the utility's average wholesale rate, as opposed to the higher retail rate offered currently.[124]

FITs are currently only offered by NIPSCO for wind, solar, or sustainable biomass or biogas projects sized between 3 kW-1 MW – purchase rates vary from around 9.18 cents/kWh for

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[116] Reasonable financial incentives are those that "encourage implementation of cost-effective energy efficiency programs" or "eliminate or offset regulatory or financial bias against energy efficiency programs or in favor of supply side resources." (Source: Indiana General Assembly. *Senate Enrolled Act No. 412.* 2015)

[117] Indiana General Assembly. *Senate Enrolled Act No. 412.* 2015.

[118] Ibid.

[119] Indiana Utility Regulatory Commission. *2019 Year-End (2019YE) Net Metering Reporting Summary.* March 2020.

[120] Notably, if a customer ceases participation in the net metering program, any unused bill credits revert to the utility. (Source: DSIRE. *Net Metering.* Last updated August 18, 2017.)

[121] Indiana Utility Regulatory Commission. *2019 Year-End (2019YE) Net Metering Reporting Summary.* March 2020.

[122] Ibid.

[123] Ibid.

[124] State Utility Forecasting Group. *2019 Indiana Renewable Energy Resources Study.* September 2019.

biomass to 23 cents/kWh for micro-wind projects.[125] Previously, IPL also offered FITs to customers, although this program was phased out in 2013.[126] Across both programs, approximately 127 MW of renewable generation capacity has been contracted under FITs in Indiana (89% solar, 11% biomass, and around 0.1% wind).[127]

Key takeaways

- Electricity generation in Indiana is dominated by coal (59% as of 2019), natural gas (31%), and wind (6%) resources. Indiana's resource mix has evolved significantly over the past decade, with coal's share of generation declining from 90% in 2010, coupled with both natural gas and wind generation increasing over the same period (up from 5% and 2% of generation in 2010, respectively).
- According to the most recent IRPs filed by Indiana's regulated utilities, as much as 7.7 GW of coal is set to retire by 2028 (29% of 2019 total installed summer capacity from all resources), to be replaced primarily by additions in natural gas, solar, and wind powered generation (3.3 GW, 4.8 GW, and 1.6 GW by 2030, respectively).
- Indiana's voluntary CPS, the CHOICE program, was adopted in 2011 with a goal of acquiring 10% of electricity from clean energy sources by 2025, relative to 2010 retail sales. To date there has been no participation in the program, although the state is on track to meet the program threshold – in 2019, Indiana generated 6% of electricity sales (toward that 2010 goal) from renewables (wind, solar, hydro).

[125] NIPSCO. *Feed-in Tariff*. <https://www.nipsco.com/services/renewable-energy-programs/feed-in-tariff>

[126] State Utility Forecasting Group. *2019 Indiana Renewable Energy Resources Study*. September 2019.

[127] State Utility Forecasting Group. *2019 Indiana Renewable Energy Resources Study*. September 2019.

6 Regulatory framework

The electricity sector in Indiana is regulated and involves vertically integrated utilities and several IPPs. However, only IOUs and nine munis are under the jurisdiction of the state regulator (the Indiana Utility Regulatory Commission ("IURC"), or the Commission) in terms of setting rates and charges. The REMCs operating in Indiana have opted out of the IURC's jurisdiction and set their rates and charges through their Boards instead. The following chapter reviews the ratemaking process for regulated electric and gas utilities in Indiana, which begins with a utility filing an application to the Commission requesting for changes to its rates and/or terms of service. Generally, electric rates are determined using the traditional cost of service approach with several pass-through charges.

6.1 Institutional arrangements

Across the country, state regulatory bodies can generally be grouped into the following types of agencies:

- **State Public Service Commission:** state commissions are tasked with ensuring that just and reasonable rates are charged to customers for the public services they consume. Functions of a state commission can include the following: enforcing regulations that protect the public's safety and interests, studying the economic and environmental impact of utility operations, mediating disputes between a utility and its customers, ensuring system reliability, and overseeing utility plans with respect to asset maintenance;[128]
- **State Energy Office:** although the activities of these offices vary according to a state's local resources and needs, they are generally funded through State and Federal programs, such as the US State Energy Program administered by the US Department of Energy. Activities of a state energy office often include, but are not limited to: advising governors and legislators on energy issues, ensuring the needs of consumers are considered during energy policy and program development, and assisting in achieving energy-related climate and environmental goals;[129] and
- **State Department of Environmental Protection:** these departments are tasked with regulating a state's air, land, and water resources. They "provide air permits for the construction of pollutant emitting assets, ensure public safety by cleaning contaminated sites, and monitor emissions by companies."[130]

Figure 60 illustrates the various regulatory agencies involved in the energy sectors in Indiana and its neighboring states. The key institutions involved in Indiana's electricity market and its regulatory framework are the IURC, Indiana Office of Energy Development ("OED"), and the Indiana Department of Environmental Management ("IDEM"). These agencies, as well as the

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[128] US DOE. *United States Electricity Industry Primer.* July 2015.

[129] National Association of State Energy Officials. *State Energy Offices* <https://www.naseo.org/state-energy-offices>

[130] US DOE. *United States Electricity Industry Primer.* July 2015. p. 27.

Indiana Office of Utility Consumer Counselor ("OUCC"), are discussed in more detail in the subsections below.

Figure 60. Regulatory agencies in Indiana and neighboring states

Sources: Regulator/department websites

Notably, all states in the region (i.e., Indiana, Illinois, Kentucky, Michigan, and Ohio) have some form of a state commission, a state energy office, as well as a government department focused on environmental protection efforts. Often, and as is the case for Illinois, Kentucky, and Michigan, the state energy office and department of environmental protection are housed under the same department. In the case of Indiana, however, these regulatory agencies are separate.

6.1.1 Indiana Utility Regulatory Commission

Indiana Code 8-1-1-1 to 16 defines and governs the IURC's general functions, responsibilities, staffing, and reports. In terms of its general functions, the IURC regulates different aspects of utilities' businesses and is mandated by state statutes to make decisions in the public interest, to ensure that utilities provide safe and reliable service at fair and reasonable rates. The Commission's responsibilities include reviewing rates and charges of electricity utilities, natural gas local distribution companies, and intrastate pipelines.[131]

Currently, the Commission regulates the rates and charges of the five electric IOUs and nine munis, namely Anderson, Auburn, Crawfordsville, Frankfort, Kingsford Heights, Knightstown, Lebanon, Richmond, and Tipton.[132] Some of the munis have withdrawn from the Commission's authority over rate regulation. Similarly, the IURC does not have oversight on the rates and charges set by REMCs, as all of Indiana's co-ops have withdrawn from the Commission's

[131] In addition to these, the IURC also regulates steam, water, and non-municipal wastewater utilities.

[132] IURC. *9 Municipal Utilities*. Available online < https://www.in.gov/iurc/files/Electric_Regulated_Utilities_7-8-13.pdf> Accessed August 5, 2020.

oversight.[133] Meanwhile, the Commission also regulates the rates of 15 natural gas IOUs (including NIPSCO and Vectren), one muni, and one not-for-profit.[134] Like some of the electric munis, most of the gas munis have withdrawn from the Commission's jurisdiction. The Commission also has the authority to initiate investigations of regulated utilities' rates and practices.

In addition, the IURC monitors and evaluates regulatory and policy initiatives affecting the State's electric and natural gas industries. Moreover, the Commission reviews and decides regulatory proceedings involving increases in rates, environmental compliance plans, permission to build or purchase power generation, energy efficiency programs, reliability, service quality, fuel cost adjustments, gas cost adjustments, service territories, and related matters. It also monitors RTOs, integrated resource planning, and demand-side management initiatives. Finally, the IURC also enforces State and Federal regulations for all intrastate natural gas facilities. The Commission has jurisdiction over two intrastate pipelines—Heartland Pipeline ("Heartland") and the Ohio Valley Hub Pipeline ("OVH")—and regulates the pipelines' operations, services, and rates.

Overall, the mandate for the IURC is relatively broad, and is not just limited to energy utilities. The Commission is responsible for regulating electric, natural gas, steam, water, and wastewater utilities.[135] This broad mandate is not unusual, with multi-sector oversight seen in all states across the region, as demonstrated in Figure 61.

Figure 61. Regulator mandates in Indiana and neighboring states

Commission	Electric	Natural Gas	Water	Pipeline (intrastate)	Telecomm-unications	Transport-ation	Railroads
Indiana Utility Regulatory Commission	Yes	Yes	Yes	Yes	Yes	No	No
Illinois Commerce Commission	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Kentucky Public Service Commission	Yes	Yes	Yes	Yes	Yes	No	No
Michigan Public Service Commission	Yes	Yes	No	Yes	Yes	No	No
Public Utilities Commission of Ohio	Yes	Yes	Yes	Yes	Yes	Yes	Yes

Sources: Regulator websites and annual reports

Five commissioners—appointed by the Governor—oversee the Commission. The commissioners serve staggered four-year terms.[136] Three of the commissioners, including the chairman, are of the same political party as the governor. The Commission has a total professional staff of about 75 people with diverse backgrounds (i.e., attorneys, engineers, accountants, and economists),

[133] For the purpose of rate and charges setting as well as obtaining financing, the state allows REMCs to withdraw from IURC's jurisdiction. The last REMC to be under IURC was Northeastern REMC, which withdrew in September 2012.

[134] IURC. *Annual Report.* 2020.

[135] IURC. *Mission Statement, History & Responsibility.* <https://www.in.gov/iurc/2451.htm>

[136] IURC. *About the IURC* - IN.gov. <https://www.in.gov/iurc/2451.htm> Accessed August 5, 2020.

who advise the Commission on cases and other issues.[137] This aligns with the commission structure adopted throughout much of the US, where public service commissions usually comprise of between three to seven commissioners serving staggered five-or six-year terms, including one commissioner acting as the chair.[138]

6.1.2 Indiana Office of Energy Development

The OED was established in 2013 under then Governor Michael R. Pence, and was charged with developing a comprehensive energy plan, administering all energy-related programs in the State, conducting research to support the development of Indiana's energy resources, and working with local research institutions to commercialize new energy technologies.[139] The OED administers various energy programs such as community energy and conservation challenge grants, and the Hoosier Homegrown Fuels Program. Moreover, it coordinates state energy policy with the executive branch agencies and administers grant programs funded by the US DOE. According to the Staff Directory listed on the OED's website, the Office comprises of four employees: an Executive Director, Policy Advisor, Policy Analyst, and Grants and Finance Manager.[140]

6.1.3 Indiana Department of Environmental Management

Under Title 13 of the Indiana Code, the Indiana General Assembly established the IDEM and its overall mission to "implement federal and state regulations to protect human health and the environment while allowing the environmentally sound operations of industrial, agricultural, commercial and government activities vital to a prosperous economy."[141] The IDEM began operating in 1986 and comprises of the following legislatively mandated divisions: air and water pollution control, solid waste management, pollution prevention, administrative services, as well as offices to handle environmental emergencies, public communication, and investigations.[142] IDEM staff totals approximately 770 employees,[143] comprising of: engineers, scientists, and environmental project managers specializing in air, land, and water quality issues and pollution prevention; as well as lawyers, investigators, and administrative staff.[144]

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[137] IURC. *Employment Opportunities - Indiana.* <https://www.in.gov/iurc/2345.htm> Accessed August 5, 2020.

[138] Lexology. *Electricity Regulation in the USA.* November 6, 2018. <https://www.lexology.com/library/detail.aspx?g=6decf3ec-4cf8-4930-8a8a-d1a69ac8ba18>

[139] State of Indiana, Executive Department Indianapolis. *Executive Order 13-06: Creation of the Indiana Office of Energy Development.* 2013.

[140] OED. *Contact Us.* <https://www.in.gov/oed/2831.htm>

[141] IDEM. *Environmental Laws and Rules.* <https://www.in.gov/idem/legal/2370.htm>

[142] IDEM. *About.* <https://www.in.gov/idem/4097.htm>

[143] Indiana Transparency Portal. *Environmental Management Employment Trend.* Accessed October 20, 2020.

[144] IDEM. *About.* <https://www.in.gov/idem/4097.htm>

6.1.4 Indiana Office of Utility Consumer Counselor

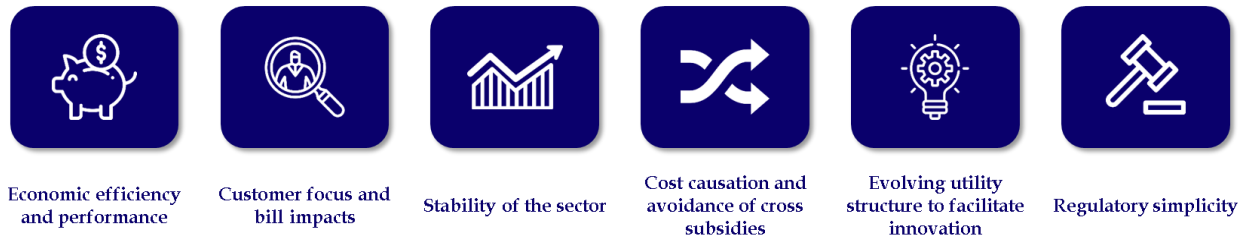
Created under Indiana Code 8-1-1.1, the OUCC represents the interests of utility customers to "ensure quality, reliable utility services at the most reasonable prices."[145] It acts in consumers' interests in cases before the IURC, FERC, and the courts (i.e., Indiana Court of Appeals and the Indiana Supreme Court). It is a separate state government agency from the IURC and is a party to each IURC proceeding. The OUCC comprises over 50 employees, "including attorneys, analysts, engineers, and additional employees who represent Indiana's residential, commercial, and industrial ratepayer interests in state and federal utility regulatory proceedings."[146]

6.2 Ratemaking process

6.2.1 Principles of ratemaking

A prudent ratemaking process aims to ensure the provision of reliable electric service at a just and reasonable cost to consumers. According to the foundational principles identified by James C. Bonbright, rates should have practical attributes including "simplicity, understandability, public acceptability, and feasibility of an application."[147]

Figure 62. Principles of ratemaking



In general, broadly accepted principles of ratemaking can be categorized into six groups, as illustrated in Figure 62 and described in further detail below:

1. ***economic efficiency and performance***: rates should provide sufficient funding to maintain reliability consistent with customer expectations while recognizing such preferences are increasingly varied;
2. ***customer focus and bill impacts***: rates should encourage the pursuit of opportunities for better cost containment;
3. ***stability of the sector***: rates should send investment signals that are proportional to the associated risk and market returns; remuneration should take the impact on debt service coverage ratios and associated parameters for maintaining an efficient capital structure

[145] OUCC. *About the OUCC*. < https://www.in.gov/oucc/2364.htm>. Accessed July 27, 2020.

[146] Ibid.

[147] Bonbright, James C., Principles of Public Utility Rates, Columbia University Press, New York NY, 1961.

into account. Moreover, stranded costs should be identified, quantified, and recovered in a fair manner;

4. ***cost causation and avoidance of cross-subsidies:*** as discussed in Section 2.3, one of the most fundamental utility rate design principles is that the customer that causes a cost to be incurred should pay that cost. If cost causation could be perfectly identified, cross-subsidies (either between or within customer classes) could be avoided;
5. ***evolving utility structure to facilitate innovation***: the rate framework must balance incumbent opportunities against market participation, reducing barriers to third-party providers of services. This also includes the elimination of capex, ownership, and technology biases and emphasizes the focus on a long-run, least-cost approach that values optionality for determining solutions to identified system and customer needs; and
6. ***regulatory simplicity***: ratemaking must balance appropriate oversight with administrative simplicity to avoid an overly burdensome process for all parties. Moreover, the framework must have built-in decision and evaluation criteria to increase accountability and advance strong stakeholder support.

Indiana state statutes regarding public utilities closely align with the principles summarized above. According to IC 8-1-2-4, "[e]very public utility is required to furnish reasonably adequate service and facilities" and dictates that charges for such services "shall be reasonable and just."[148] Notably, the mandate of the regulator is not necessarily to "lower" the rates charged to customers, but rather to consider and adequately balance the interests of **utilities**—with respect to cost recovery and reasonable return on capital investment—and **consumers**, with regard to fair and affordable rates and reliable service.

Electricity rates in Indiana are generally determined using a cost of service approach, where the utilities need to demonstrate the necessity and reasonableness of capital investments and operating costs to deliver electric service. Each of the utilities also utilizes certain automatic rate adjustment clauses to adjust for variability in fuel or purchased power costs between rate cases ("trackers").

Furthermore, Indiana passed the Alternative Utility Regulation ("AUR") Act in 1995. Under this law, utilities can choose to adopt alternative regulatory mechanisms and establish rates and charges based on market or average prices, price caps, index based prices, and prices that use performance-based rewards or penalties (either related or unrelated to the energy utility's return or property), which are designed to promote efficiency in providing retail energy services.[149] Rates and charges are to be in the public interest and enhance or maintain the value of the energy utility's retail energy service or properties.[150] Utilities that plan on adopting an alternative regulation are required to submit an alternative plan to the Commission, which the IURC will review and either approve, deny, or revise. The energy utility may then accept or reject the

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[148] IC 8-1-2-4: Services to public; rates and charges. <http://iga.in.gov/legislative/laws/2020/ic/titles/008#8-1-2-4>

[149] Indiana Code § 8-1-2.5-6. Title 8, Article 1, Chapter 2.5 Alternative Utility Regulation.

[150] Indiana Code § 8-1-2.5-6.

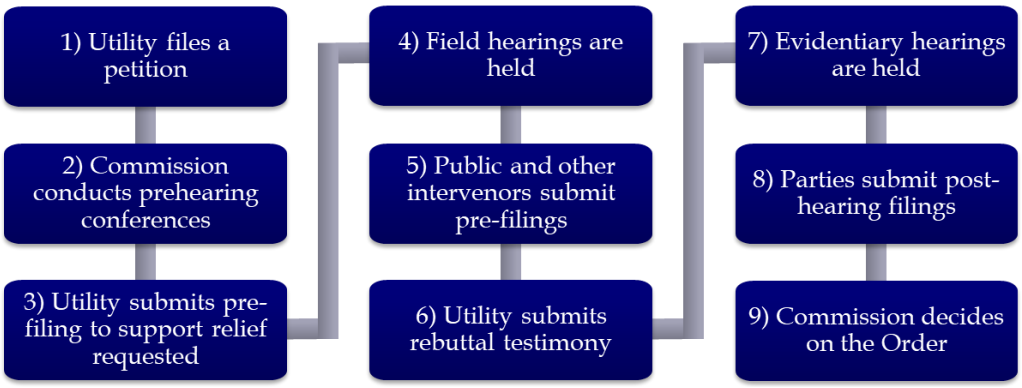
Commission's Order modifying the proposed plan. An energy utility may also withdraw a proposed plan prior to the Commission's approval.[151] However, LEI understands that no utilities have proposed or adopted (through an alternative regulatory plan) any of the performance-based ratemaking ("PBR") aspects of the regulation to date.[152]

6.2.2 Ratemaking process for utilities under the IURC

The IURC follows a series of nine steps in its ratemaking process (Figure 63) for both electric and gas utilities. This process is relatively standard and is used in many jurisdictions throughout the country. The process starts when a utility files an application with the IURC requesting changes to its rates and/or terms of service. The application typically includes details on the proposed changes, relevant supporting data, and testimony. According to the Indiana Code § 8-1-2-42(a), a utility can only file for a general increase in its basic rates and charges fifteen months after filing the last request for an increase.[153] Under a deadline established in Indiana Code § 8-1-2-42.7, the IURC has 300 days from the time a utility files its case in chief to issue an order.[154] Parties to the case may appeal the Commission's decision to the Indiana Court of Appeals.

Upon receiving an application, the Commission staff then reviews the filings and, if necessary, requests additional information from the given utility. Moreover, the Commission allows relevant stakeholders (also referred to as intervenors), such as representatives of consumers and industrial groups, to file their recommendations regarding the given case. The OUCC is statutorily a party to all rate cases presented before the IURC on behalf of all customers.

Figure 63. Ratemaking process



Note: As noted by the IURC, "settlement hearings occur when the parties present the terms of a negotiated settlement to the Commission for consideration. Settlements must generally be reached before the last evidentiary hearing."

Source: IURC. *Standard Procedural Schedule for Rate Cases.*

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[151] Ibid

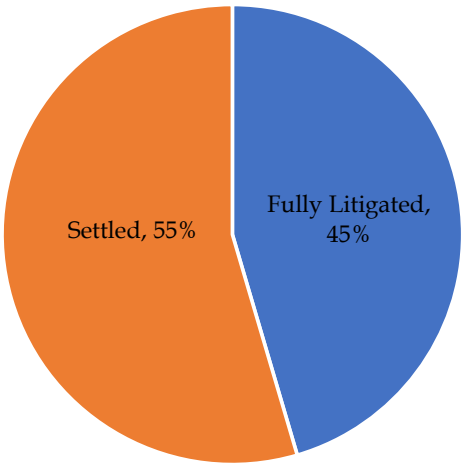
[152] LEI correspondence with IURC Assistant General Counsel (September 30, 2020).

[153] IURC. *Rate Case Overview and Process*. < https://www.in.gov/iurc/2995.htm> Accessed July 27, 2020.

[154] Indiana Code § 8-1-2-42.7.

In Indiana, electric and natural gas rate case proceedings are resolved either by settlements or are fully litigated. From 2011 to July 2020, 45% of rate case proceedings in the State were fully litigated, as shown in Figure 64. A rate case settlement is not unusual in the region. Indiana's neighboring states have settled some rate cases in the past ten years, as presented in Figure 65.

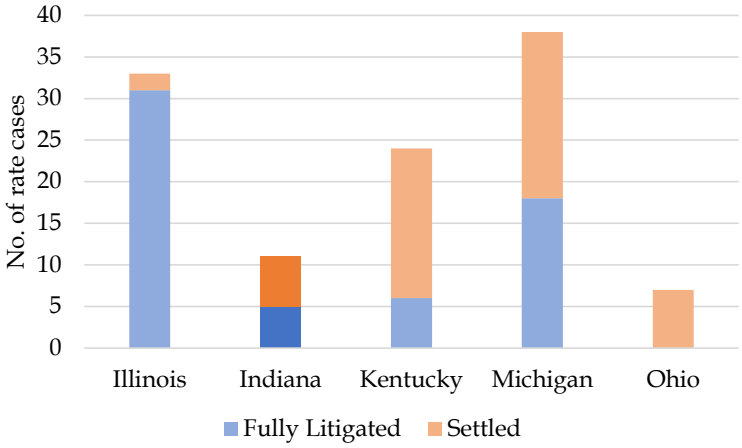
Figure 64. Settled versus fully litigated rate cases in Indiana (2011-2020)



Note: As of July 2020; the rate cases above include both electric and natural gas; they do not include rate cases for limited-issue riders (trackers).

Source: Commercial third-party database (Accessed on July 17, 2020).

Figure 65. Settled versus fully litigated rate cases in neighboring states (2011-2020)

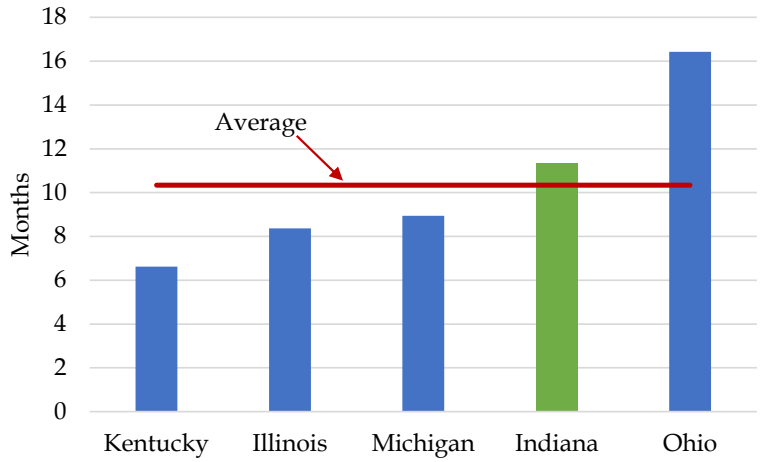


Note: As of July 2020; the rate cases above include both electric and natural gas; they do not include rate cases for limited-issue riders (trackers).

Source: Third-party commercial database (Accessed on July 17, 2020).

In Indiana, a rate case takes between 10 to 12 months from the initial filing to the date of the Commission's decision.[155] In contrast, Ohio, which has had nearly all of its rate cases settled, tends to take the most time to complete a rate case: from a year to a year and a half. A shorter rate case process means a lower regulatory burden for the regulator, utility, and customers. Figure 66 shows the average duration of rate cases for the past ten years in Indiana, as well as in its neighboring states.

Figure 66. Average duration (in months) of rate cases for the past ten years in Indiana and neighboring states



Source: Third-party commercial database (Accessed on July 17, 2020).

6.3 How revenue requirements are set

As mentioned earlier, the IURC has jurisdiction over the ratemaking process for generation and distribution, while transmission ratemaking is based on FERC-authorized transmission formula rates via MISO or PJM. This section discusses how revenue requirements are set for IOUs under the IURC, and transmission under FERC jurisdiction within MISO and PJM. The ratemaking process and components of revenue requirements for munis and REMCs that are not under the IURC's jurisdictions are briefly discussed in Sections 6.3.2 and 6.3.3, respectively.

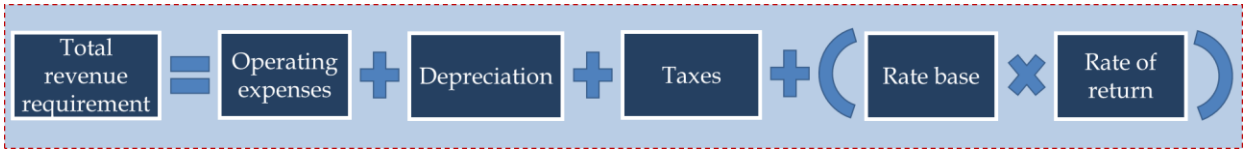
6.3.1 Revenue requirements for IOU state regulated activities

A utility incurs various costs in fulfilling its obligation to serve its customers. These costs are identified to determine the total revenues that must be recovered from ratepayers, to ensure that the utility can cover its costs and earn a reasonable return on equity for its shareholders. The revenue requirement is then the amount of revenues the utility needs to cover the cost of service, which includes depreciation, the return to investors, and operating costs. The determination of the revenue requirement is essential for the utility to recoup its cost of service. The total revenue

[155] IURC. *Rate Case Overview & Process*. < https://www.in.gov/iurc/2995.htm> Accessed August 5, 2020.

requirement is estimated by determining the rate base and multiplying this by an allowed rate of return plus the operating costs (Figure 67).

Figure 67. Revenue requirement formula for an IOU



Note: There are also pass-through charges such as fuel cost adjustment trackers. These are discussed in Section 6.3.6.

Source: IURC. *Indiana Utility Guide.* 2019 Edition.

IOUs in Indiana include the following items in their revenue requirements:[156]

- operation and maintenance expenses;
- depreciation;
- income taxes and income tax credits;
- taxes other than income; and
- return on investment (weighted cost of capital x rate base).

These items are discussed in further detail below.

Calculating the rate base

In general, determining the Regulated Asset Base ("RAB") is a crucial component in the rate-setting process for an IOU. The RAB comprises prudent investments made by the utility to provide electric service, and includes utility-owned generation facilities, buildings, poles, wires, transformers, meters, vehicles, and computers. The RAB is the investment base on which a fair rate of return is applied to arrive at the allowed return to investors.

Rate base is the amount of money the utility has invested in the facilities that serve customers, minus accumulated depreciation, but including working capital and materials and supplies required to keep the company operating.

Source: IURC. *Indiana Utility Guide.* 2019.

Ultimately, choosing which approach to use to develop RAB estimates must depend on the specificities of the jurisdiction's regulatory and economic context. Such peculiarities include the perceived accuracy of utility accounting data related to the RAB, ongoing viability of existing assets on the books, and the impact that any values may have on tariffs and end-consumers' ability to pay for electricity supply. The components included in the RAB for utilities under the IURC's authority are summarized in Figure 68.

[156] IURC. *Indiana Utility Guide.* 2019 Edition.

Figure 68. Rate base components for large utilities under IURC authority

Rate base	
Add:	*Less:*
Utility Plant in Service	Accumulated Depreciation
Allowance for Funds Used During Construction ("AFUDC")	Contributions in Aid of Construction
Materials and Supplies (13-month average)	Customer Advances for Construction
Deferred Depreciation (if approved)	
Post-in-Service AFUDC (if approved)	
Acquisition Adjustments, net (if approved)	

Source: IURC. *Indiana Utility Guide.* 2019 Edition.

Determining the rate of return

The second component of the revenue requirements is the **allowed rate of return**. This is expressed as a percentage and essentially represents the amount of return that investors will receive on their investment, the asset base. Setting the allowed rate of return requires balancing two equally important objectives: incentivizing continued investment in the sector and ensuring that consumers pay just and reasonable rates. There is ultimately no single correct allowed rate of return but rather a "zone of reasonableness" within which judgment must be exercised.[157] The lower bound of this zone represents the minimum return required to continue attracting capital, while the upper bound represents the return that an investment of similar risk could make elsewhere.

> The **allowed return** is the money required to pay interest costs on borrowed money plus the additional amount paid to the shareholders for the use of their money. The required return is calculated by multiplying the utility's rate base by its cost of capital – that is, what it costs the utility to obtain capital from lenders and from shareholders.
>
> Source: IURC. *Indiana Utility Guide.* 2019.

The predominant method for setting the allowed rate of return is to use the regulated firm's Weighted Average Cost of Capital ("WACC").[158] In this approach, the allowed rate of return is set equal to the firm's WACC, suggesting that the firm is being compensated for its capital costs. This implies that the firm will make a nominal but not an economic profit.

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[157] Kahn, Alfred, *The Economics of Regulation: Principles and Institutions,* Cambridge, MA: MIT Press, 1988. P. 42/I.

[158] There are a number of methods that could be used to set rates of return for a utility. Historical rates, "a priori" (model-based), and the WACC have all been used by financial practitioners in determining what the rate of return should be for an investment. Each of these could be applied to determine what return the utility should be allowed to make, in order to provide enough incentives for investment. Notably, of these three methods, only WACC is in common use in utility rate setting, although historical rates are sometimes used to set parameters utilized in estimating WACC.

WACC is the total cost, in percentage terms, of financing the firm's assets. It is calculated as:

$$WACC=[D\times R_D] + [(1-D)x\ R_E]$$

Where D=ratio of debt to assets, R_D=cost of debt (after-tax), and R_E=cost of equity

To calculate the WACC, a number of inputs are required: the cost of equity, the cost of debt, and the capital structure to be used.

However, it is important to note that the IURC considers the cost of capital estimation to be "only one factor" in determining the fair rate of return. The Commission has repeatedly found "that cost of capital is not synonymous with the fair rate of return. Ultimately, the determination of a fair rate of return is the prerogative of the Commission, taking into consideration all the relevant evidence."[159] The goals of a fair rate of return "go well beyond the use of formulas and mathematical calculations which may imply a level of precision which does not really exist… Rather, [the IURC is] to exercise the flexibility afforded to [it] by statute and the Indiana Supreme Court."[160]

Figure 69 lists the returns on equity ("ROEs") and proportion of common equity authorized by the IURC in the most recent rate cases for each of Indiana's five IOUs. On average, allowed ROEs have been set at around 9.91%, with a common equity to total capital proportion of 41.90%. However, given that Vectren has not filed for a base rate increase since its case was completed in 2011, excluding it from the state average (and focusing only on rate cases completed during the 2018-2020 period) brings the allowed ROE down to 9.79%, and the common equity proportion down to 41.52%. The former is slightly higher than the national average (for rate cases completed in the same 2018-2020 period) of 9.59% (ROE), while the latter is moderately lower than the national average of 49.41% (common equity proportion).

Figure 69. Authorized ROEs in past Indiana electric utility rate cases versus national average

Utility	Docket	Year	Authorized ROE	Common equity to total capital
Duke	Cause 45253	2019-2020	9.70%	40.98%
I&M	Cause 45235	2019-2020	9.70%	37.55%
IPL	Cause 45029	2017-2018	9.99%	39.67%
NIPSCO	Cause 45159	2018-2019	9.75%	47.86%
Vectren	Cause 43839	2009-2011	10.40%	43.46%
Indiana average (most recent rate cases)			**9.91%**	**41.90%**
Indiana average (2018-2020 rate cases)			**9.79%**	**41.52%**
US average (2018-2020 rate cases)			**9.59%**	**49.41%**

Source: Third party commercial database (accessed October 15, 2020)

[159] IURC. *Cause No. 42359*. May 18, 2004. p. 8 – referring to IURC. *Cause No. 40003*. September 27, 1996.

[160] Ibid.

Calculating the operating costs

The operation and maintenance ("O&M") expenses represent the cost of operating and maintaining the utility plant and equipment or the cost of running the utility. The administrative and general expenses include salaries and wages, office supplies, regulatory commission expenses, and general plant maintenance. The depreciation expense is the share of the initial investment that has been allocated to that year. This amount represents the recovery of the investment in facilities as opposed to profits from the investment.

Operating expenses: the costs incurred in a specific period that includes wages and benefits for employees, maintenance, educational advertising, customer services, material and supplies, energy, and administration costs, as well as taxes and depreciation.

Source: IURC. *Indiana Utility Guide.* 2019.

6.3.2 Revenue requirements for munis

The rates and charges of munis operating in Indiana are either approved by the IURC, or the respective municipality's legislative body/city council (for those operating outside of the IURC's jurisdiction for rate regulation). In the case of the former (i.e., munis under IURC authority), as governed by Indiana Code 8-1.5-3-8, the following items are included in the revenue requirement:[161]

- operation and maintenance expenses;
- extensions and replacements or depreciation;
- debt service;
- debt service reserve;
- working capital;
- taxes other than income taxes;
- payment in lieu of taxes; and
- return on investment.

As stated in Indiana Code 8-1.5-3.8, the intent is that "the rates and charges produce an income sufficient to maintain the utility property in a sound physical and financial condition to render adequate and efficient service. Rates and charges too low to meet these requirements are unlawful."[162]

In contrast, munis that are not under the IURC's jurisdiction implement rates (and associated rate adjustments) in accordance with approved municipal codes or ordinances. The locally elected city or town council serves as the muni's regulatory body. Generally, the rate-setting process

[161] IURC. *Indiana Utility Guide.* 2019 Edition.

[162] Indiana Code Title 8. Utilities and Transportation § 8-1.5-3-8. <https://codes.findlaw.com/in/title-8-utilities-and-transportation/in-code-sect-8-1-5-3-8.html>

involves hiring an independent consultant to conduct a cost of service study ("COSS"), who then presents the findings of the study and makes recommendations to the relevant regulatory body, engaging stakeholders, issuing a final decision, and petitioning the decision for review (if applicable). These COSS may be of a different level of detail and analysis from those submitted by IOUs to the IURC.

Overall, munis—whether they are under IURC jurisdiction or not—collect rates and charges that produce sufficient revenues to pay expenses related to the operation of the utility.

6.3.3 Revenue requirements for co-ops

As discussed previously, REMCs in the State are not under IURC jurisdiction in terms of rate approval. As such, the elected Boards representing REMCs are responsible for balancing the consumers' and the co-op's interests, creating a certain degree of self-regulation. The Board decides on whether to raise electric rates and approve rate changes, and is also responsible for ensuring that electric rates are adequate to maintain the co-op's financial health.

Generally, an REMC's revenue requirements include the costs associated with purchased power, depreciation, interest, O&M, general, as well as administrative expenses. No return on equity is factored into the revenue requirement, as an REMC's equity is held primarily by its customer-members, who make contributions for service without an expectation of return. However, REMCs typically operate with an annual revenue margin in order to be eligible for financing or compliant with loan covenants.

6.3.4 Revenue requirements for transmission

As discussed briefly in Section 5.2.2, while transmission owners have financial ownership over the transmission assets, the control of flows on the transmission system lies with RTOs. MISO and PJM are responsible for collecting and disbursing the transmission revenue requirements for utilities in its RTO, including Indiana.

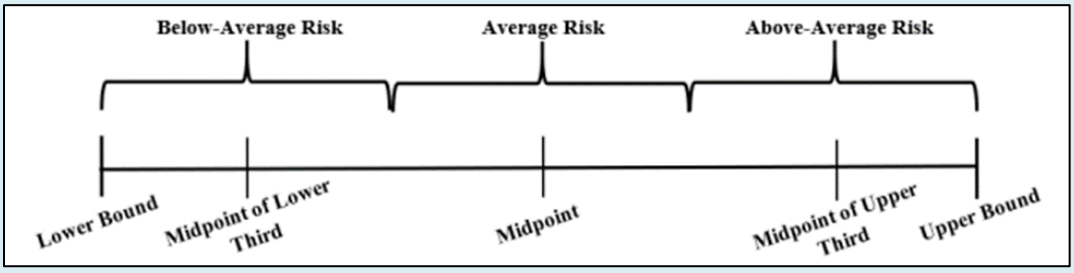
According to the Open Access Transmission Tariff, the process of determining the revenue requirements starts with the utilities determining their annual transmission revenue requirement ("ATRR"). Utilities will determine their ATRR using a FERC-approved Transmission Formula Rate and submit it to MISO/PJM, as well as to FERC as an informational filing. While transmission rates are FERC regulated, the transmission owners have to testify in front of the IURC to defend their transmission rates, because rate cases filed by a utility to the IURC cover allocation of transmission costs to different customer classes.

FERC Transmission Formula Rates

A selection of financial models which assess risk and return are routinely utilized by FERC in its determinations and setting of just and reasonable base transmission ROEs. Specifically, FERC relies on three financial models as part of its methodology, including the capital asset pricing model ("CAPM"), the discounted cash flow ("DCF") model, and the risk premium model. FERC has acknowledged that by relying on these various financial models, it aims to set "a more accurate estimate of what ROE is needed to induce investors to invest in a utility – i.e., what ROE a utility must offer in order to attract capital."

Under this approach, FERC calculates a 'zone of reasonableness' using a weighted average of the results of all three financial models. This determines a range of ROEs which are presumed to be just and reasonable. The range, as presented in a May 2020 FERC Order, is depicted in the figure below. Essentially, the spectrum demonstrates that for average risk utilities, the Commission proposes the appropriate range of ROEs would be around the mid-point of the zone of reasonableness.

FERC's ROE policy is currently in a state of flux, being the subject of a formal inquiry, rulemaking, multiple contested cases, and at least two appellate proceedings. However, under the most recent methodology presented in the May 2020 Order, the base ROE for MISO transmission owners has been set at 10.02%. Under a previous iteration of FERC's policy, AEP Transco's ROE was set at 10.35% (PJM).



Sources: FERC. *Opinion No. 569, Order on Briefs, Rehearing, and Initial Decision, Docket Nos. EL14-12-003 and EL15-45-000.* November 21, 2019; FERC. *Opinion No. 569-A, Order on Rehearing, Docket Nos. EL14-12-004 and EL15-45-013.* May 21, 2020. FERC. *FERC Revises Public Utility ROE Methodology; Sets Policy for Natural Gas, Oil Pipelines.* May 21, 2020. S&P Global Market Intelligence. *Election could prompt big changes at FERC, reshape ROE and incentives policies.* October 13, 2020. Fitch Ratings. *Fitch Ratings Affirms LT IDR of AEP Transmission Company LLC at 'A-'; Outlook Stable.* April 13, 2020.

As MISO and PJM are multi-state RTOs, and electricity generated in other states is transmitted and consumed in Indiana, transmission investments and associated costs in other states may benefit consumers in Indiana, and vice-versa. At the same time, there are transmission projects that only benefit a specific transmission zone within the system. Finally, some projects are developed to allow specific generation resources to be interconnected to the grid. Therefore, MISO adopts a hybrid cost allocation mechanism that results in a different transmission rate throughout the RTO, depending on a consumer's location.

MISO develops an annual MISO Transmission Expansion Plan ("MTEP") to identify investment needs related to long-range transmission system projects for the MISO Board to approve. These projects are grouped into eight categories – Baseline Reliability Projects ("BRPs"), Generation Interconnection Projects ("GIPs"), Market Efficiency Projects ("MEPs"), Targeted Market Efficiency Projects, Multi-Value Projects ("MVPs"), Others, Transmission Delivery Service Projects, and Market Participant Funded Projects. Generally, BRP costs are allocated to local Transmission Pricing Zones, while MEP costs are allocated to regions based on the benefit they would receive from the project. GIPs are paid for by the generation resources that requested the connection, and therefore do not directly result in consumer rate changes. Since 2011, MISO has approved 17 MVPs, which are large inter-regional high voltage projects that have rate impacts through 2054. Their costs are allocated across MISO regions.

PJM adopts a similar methodology through its Regional Transmission Expansion Plan ("RTEP") process, categorizing projects into Baseline Projects, Network Projects, Transmission Owner Supplemental Projects, and Merchant Transmission Projects (which would not directly impact transmission rates).

6.3.5 Rate design

Rate design refers to the itemized pricing structure reflected in consumers' monthly electric bills, including the underlying mechanism used to derive the rates.[163] Rate design is the final step in the COS mechanism following the allocation of costs to different customer classes, including residential, commercial, industrial, and others. The intent of rate design is to incent efficient use of the system, in addition to providing utilities a fair opportunity to recover their costs. Rate design starts with calculating the total annual revenue requirement of a utility using the COS mechanism. Following this, the cost components are allocated to different customer classes after conducting a Class COS ("CCOS") study.[164] This form of traditional rate design is the most commonly used form of rate design by state utilities in the US, given its simplicity and strong public acceptance.[165] Rates per customer class are further divided into billing determinants, which allocate a portion of the customer class revenue requirement between volumetric (cents per kWh) based on each customer's usage, capacity (charges based on the maximum kW a customer uses in a particular period), and per customer (a fixed charge per customer). In Indiana, the majority

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[163] Lazar, Jim, and Wilson Gonzalez. "Smart Rate Design for a Smart Future." RAP, July 2015, http://www.raponline.org/wp-content/uploads/2016/05/rap-lazar-gonzalez-smart-rate-design-july2015.pdf.

[164] The CCOS Study focuses on determining the relationship between the revenue recovered from each customer class and the cost caused by each customer class and aids in categorizing and allocating total utility costs to various rate classes.

[165] Costello, Ken. "Alternative Rate Mechanisms and Their Compatibility with State Utility Commission Objectives." National Regulatory Research Institute, Apr. 2014.

of IOUs have implemented a declining block rate structure (where rates decrease with additional volumes).[166]

6.3.6 Flow through cost recovery mechanisms

In addition to recovering costs through base rate changes, utilities under the IURC's jurisdiction are allowed to recover specific cost categories through commission-authorized adjustment trackers and legislatively mandated adjustment clauses. These costs are generally outside of the utility's control. Clear processes for calculating and recovering trackers improve the utility's ability to finance itself and reduce the regulatory burden on ratepayers.

However, utilities are generally still required to prudently manage costs recovered through trackers. There may also be a lag between the cost being incurred and its recovery from ratepayers. Figure 70 shows a list of these trackers and charges, along with the range of these charges on a typical residential customer's bill (for 1,000 kWh monthly usage, July 2020 bill), as well as the IOUs using each tracker as of July 2020. Section 8.1.4 provides a more detailed discussion and breakdown as to the proportion of bills devoted to trackers, and how this varies across IOUs.

[166] Declining block rates for residential customers were approved by the IURC most recently in June 2020 for Duke (Cause No. 45253), March 2020 for I&M (Cause No. 45235), and March 2016 for IPL (Cause No. 44576). NIPSCO and Vectren both use flat energy rates for residential customers (IURC. *Utility Tariffs*).

Figure 70. List of trackers and charges in Indiana

Charges/Trackers	Description	Range on typical residential bill (1,000 kWh, July 2020)	IOUs using tracker
Clean Coal Technology Investment and Operating Costs	Includes the expenses associated with the use of Indiana's retrofitted pre-1990 coal fleet, such that its continued use will burn coal more cleanly to provide service to customers.	-	-
Demand-side Management	Includes all the programs that a utility sponsors to enhance customer participation in managing their residential/commercial energy consumption, which creates program management expenses, avoided sales, and under-recovery of a utility's fixed-cost revenue need.	($0.36) - $8.22	Duke, I&M, IPL, NIPSCO, Vectren
Emissions Allowance Costs	Encompasses the various pollutant emission control programs that facilitate allowance trading, allowing the flow-through of such costs or revenues to incentivize the utilities to pick the most efficient compliance path.	($0.01)	Duke
Federally Mandated Cyber Security Cost	Includes costs incurred related to the cybersecurity of information technology systems, driven by regulatory mandates.	-	-
Federally Mandated Environmental Cost	Includes costs incurred related to environmental investments such as clean coal technology projects, driven by regulatory mandates.	($2.64) - $9.30	Duke, I&M, IPL, NIPSCO, Vectren
Fuel Adjustment Charge	Tracks a utility's fuel expenses such as the cost of coal, uranium, and other fuels used to generate power at generation facilities. The tracker also includes costs of purchased power.	($10.22) - $14.48	Duke, I&M, IPL, NIPSCO, Vectren
Nuclear Life-cycle Management Cost	Provides for the recovery of capital investment to ensure the continued safety and reliability of the D.C. Cook nuclear facility.	$0.02	I&M
Off-System Sales Margin Sharing	Tracks sales margins from off-system sales to the wholesale power market, to be shared on a 50/50 basis with customers above and below an embedded amount (e.g., a sales shortfall would result in a charge on customer bills).	$1.33 - $20.90	I&M, IPL
Regional Transmission Operator Expenses	Includes the costs and revenues associated with the management of transmission and wholesale market operations in terms of generation and delivery by regional entities such as MISO and PJM into retail rates.	($0.10) - $4.04	IPL, NIPSCO, Vectren
Reliability Assurance or Capacity Cost	Includes the arrangements a utility makes to ensure adequate resources to meet customer needs through contract arrangements rather than the more traditional method of making plant investments. These arrangements may also include compensating larger customers for interruptible service or contracting with an independent power plant's capacity.	($2.22) - $4.11	Duke, I&M, NIPSCO, Vectren

Notes: The Off-System Sales Margin Sharing Tracker appeared as a charge on customer bills for both I&M and IPL for the July 2020 billing period. For I&M, this is because the tracker also recovers costs associated with mandated participation in PJM (see *Your I&M Residential Bill in Indiana*). For IPL, this is because off-system sales margins for the year below $16,324,000 result in a charge (above this threshold, customers receive a credit, see *Cause No 44795 OSS 4).*

Sources: IURC Annual Report, Indiana Michigan Power Rates and Tariff, IURC 2020 Residential Bill Survey

Key takeaways

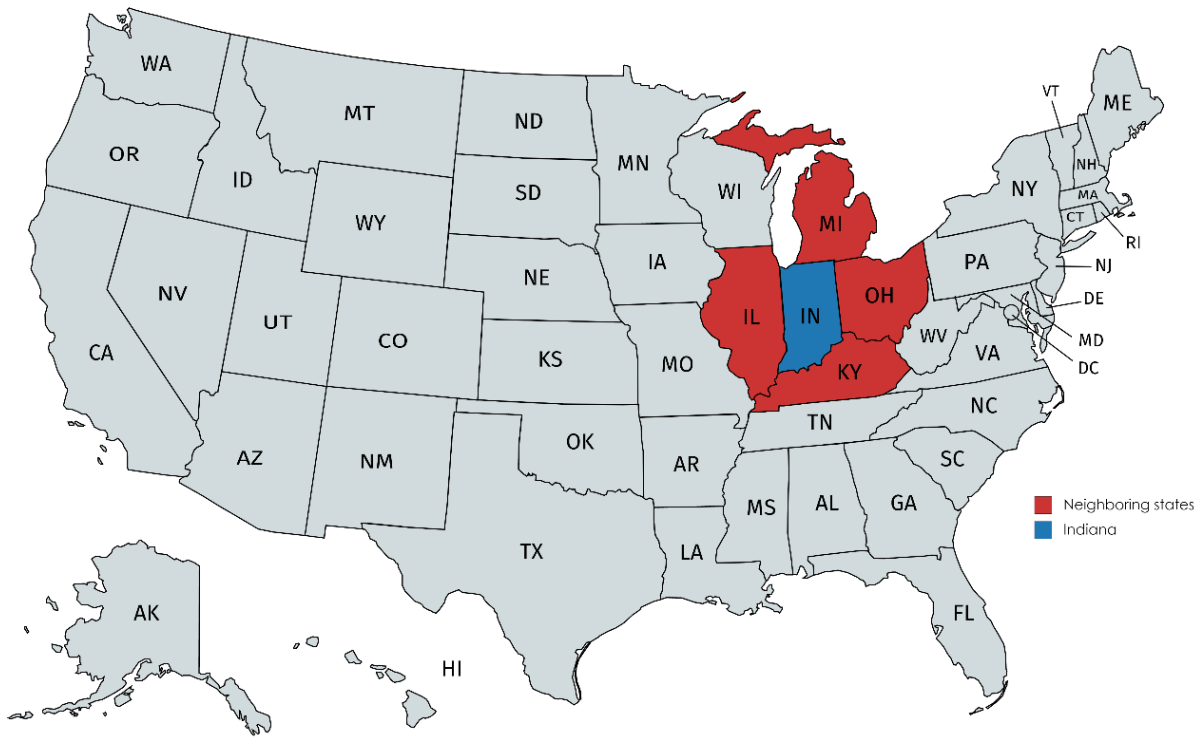
- The electricity sector in Indiana is regulated and involves vertically integrated utilities and several IPPs. These utilities are participants of either MISO or PJM.
- Only IOUs and nine munis are under IURC jurisdiction in terms of setting rates and charges; REMCs have opted out of the IURC's jurisdiction and set their rates and charges through their Boards.
- The IURC's legislative mandate in terms of rate setting is not to "lower" the rates charged to customers, but rather to ensure "just and reasonable" rates. This involves adequately balancing the interests of utilities and the customers they serve.
- The ratemaking process for electric and gas utilities in Indiana is relatively standard and used in many US jurisdictions; it starts with a utility filing an application to the Commission requesting for changes to its rates and/or terms of service. In general, the process takes a year and is fully litigated.
- Electric rates are determined using the traditional cost of service approach with several pass-through charges. Allowed returns are similar to those found in other jurisdictions.

7 Indiana's ranking on costs, affordability, and reliability

LEI looked at Indiana's ranking nationally and relative to its neighboring states by considering: (i) average electricity rates, (ii) energy affordability, and (iii) reliability. In assessing average electricity rates, LEI considered data for the last ten years (2010-2019) from the US EIA and presented findings by customer class (i.e., residential, commercial, industrial, and the all-sector average) and service provider type (i.e., IOU, co-op, and muni). Generally, Indiana's rates have increased faster than the national average, and affordability has fallen, while reliability is within national norms.

For the purpose of this Study, "region" is defined as the following neighboring states: Illinois, Kentucky, Ohio, and Michigan (Figure 71). These states were selected due to their geographic proximity to Indiana, as well as similarities to the State's organization of its electricity sector.

Figure 71. Map of the states included in this comparison



To assess energy affordability, LEI used three energy affordability metrics, namely: (i) the home energy affordability gap ("HEAG"), (ii) the home energy burden for low-income households as a percentage of gross income, and (iii) the average percentage of households facing unaffordable energy bills. LEI relied on HEAG data from Fisher, Sheehan & Colton ("FSC"), which is publicly available and used by various organizations and public entities.

To evaluate reliability, LEI used industry standard metrics such as the System Average Interruption Duration Index ("SAIDI"), System Average Interruption Frequency Index ("SAIFI"),

and the Customer Average Interruption Duration Index ("CAIDI"). LEI relied on data from the US EIA for these metrics.

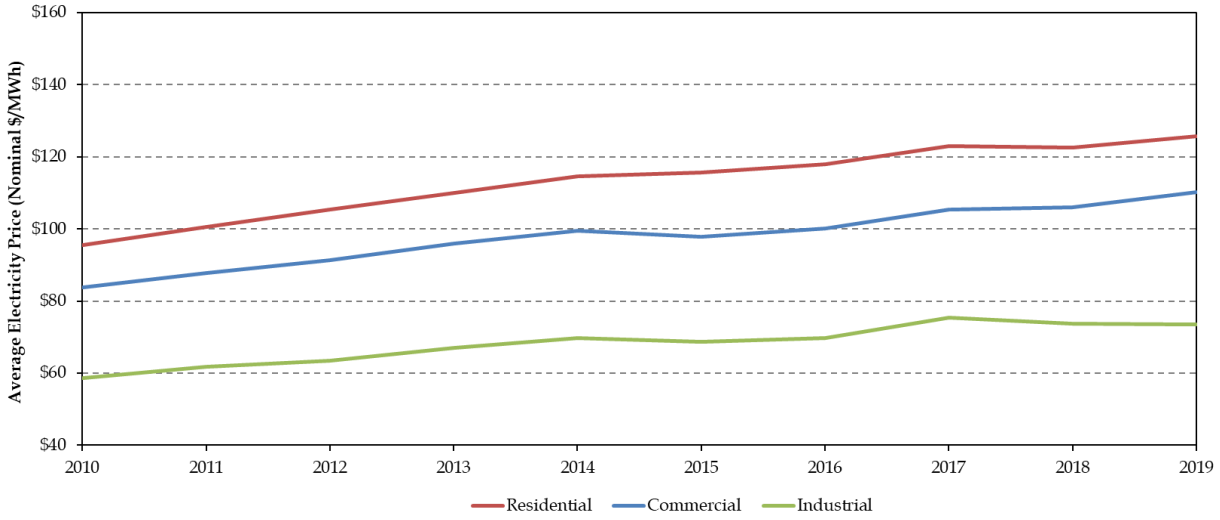
7.1 Average electricity rates

The cost rankings in this Study are based on the electricity rate charged to different customer classes. The primary source of data for this cost comparison is the US EIA's Average Price of Electricity to Ultimate Customers database. The average prices are reported for residential, commercial, industrial, and transportation[167] sectors, as well as for the entire customer base. This chapter first looks at the average electricity rate trends in Indiana, before comparing them nationally and with the neighboring states.

7.1.1 Average electricity rate trends in Indiana

Average electricity rates in Indiana vary across customer class. As is typical, average residential electricity rates have consistently been higher than average industrial and commercial rates from 2010 to 2019 (Figure 72). On average, residential rates are higher than commercial and industrial rates by 16% and 44% per year, respectively. Figure 72 also shows that average electricity rates have grown steadily across all three customer classes, rising between 2.5% and 3.1% per annum for the period 2010-2019.

Figure 72. Average electricity rates in Indiana (nominal, $/MWh)



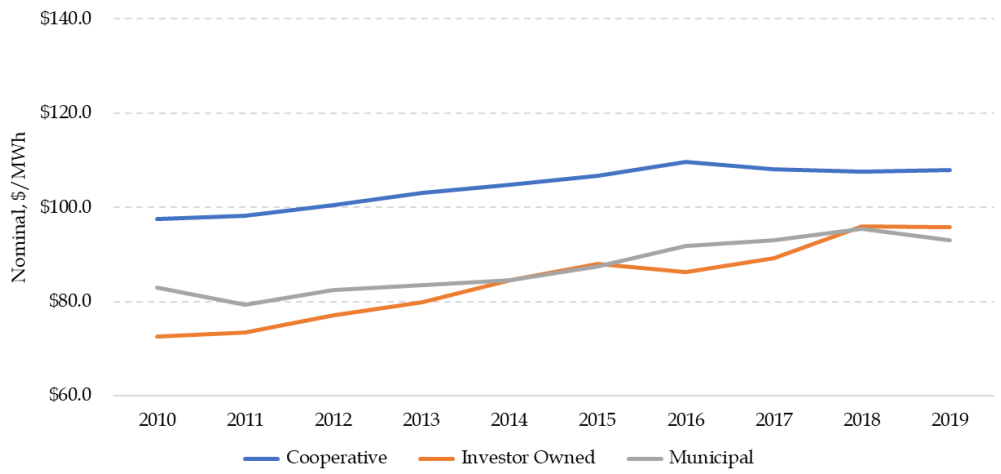
Nominal $/MWh	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	*CAGR*
Residential	$ 95.6	$ 100.6	$ 105.3	$ 109.9	$ 114.6	$ 115.7	$ 117.9	$ 122.9	$ 122.6	$ 125.8	***3.1%***
Commercial	$ 83.8	$ 87.7	$ 91.4	$ 96.0	$ 99.6	$ 97.8	$ 100.1	$ 105.4	$ 106.0	$ 110.3	***3.1%***
Industrial	$ 58.7	$ 61.7	$ 63.4	$ 67.0	$ 69.7	$ 68.6	$ 69.7	$ 75.4	$ 73.8	$ 73.6	***2.5%***

Source: Form EIA-861 – Annual Electric Power Industry Report (2010-2019)

[167] For this Study, we have focused on residential, commercial, and industrial sectors.

Likewise, average electricity rates in Indiana vary by service provider type. Generally, electricity rates charged by IOUs have been comparable to those charged by munis. On the other hand, co-ops have consistently higher average electricity rates (24% higher than IOUs and 19% higher than munis per year). This is largely a function of differences in service territory and customer numbers; it does not suggest one form of organization is inherently better than another. The average annual growth rates in electricity costs are comparable between co-ops and munis. Electricity rates among IOUs have increased faster than those charged by co-ops and munis (Figure 73).

Figure 73. Average electricity rates in Indiana by provider type (nominal, $/MWh)



$/MWh	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	*CAGR*
Cooperative	$ 97.5	$ 98.3	$ 100.5	$ 103.1	$ 104.9	$ 106.6	$ 109.6	$ 108.1	$ 107.6	$ 107.9	***1.1%***
Investor Owned	$ 72.6	$ 73.4	$ 77.0	$ 79.8	$ 84.5	$ 88.0	$ 86.3	$ 89.1	$ 95.9	$ 95.8	***3.1%***
Municipal	$ 83.0	$ 79.4	$ 82.5	$ 83.5	$ 84.5	$ 87.5	$ 91.9	$ 93.1	$ 95.5	$ 93.1	***1.3%***

Source: Form EIA-861 – Annual Electric Power Industry Report (2010-2019)

7.1.2 Electricity rates relative to the national average

Over the last ten years, Indiana's national ranking for electricity prices across all customer classes has worsened significantly. As illustrated in Figure 74, the decline has been most substantial for commercial customers, with electricity prices falling from 18th best in the country in 2010 to 37th by 2019 (down 19 places), followed by industrial (16th to 32nd – down 16 places) and residential customers (17th to 31st – down 14 places). Averaged across all customer classes, Indiana ranked 28th in the nation in terms of electricity prices (2019), down from 13th in 2010. Within each customer class, Indiana has gone from ranking within the top half cheapest states in the nation, to the bottom half over the 2010 to 2019 period. The tables in Figure 78 through Figure 81 below depict this decline in national ranking broken down by year for each customer class.

Figure 74. Indiana's national ranking for electricity prices by customer class (2010 versus 2019)

Source: Form EIA-861 – Annual Electric Power Industry Report (2010-2019)

Over the 2010-2019 period, electricity rates increased at a CAGR of 0.8% on average across the nation. 36 states experienced rate increases greater than the 0.8% per annum average. Figure 75 lists the top ten states in the US in terms of total average electricity rate increase for the period; Indiana ranks 5th in the nation, with average electricity rates increasing by 2.9% per annum. Notably, half of the top ten states listed in the table (including Indiana) were ranked among the top ten states in the nation relying on coal for electricity generation as of 2019 – the states appearing on both lists (i.e., greatest electricity rate increase for 2010-2019, and greatest reliance on coal for electricity generation for 2019) are bolded in the table below.

Figure 75. Top ten states in terms of electricity rate increase (2010-2019)

	State	Total average electricity rates		CAGR
		2010	2019	
1	Alaska	14.8	20.2	3.6%
2	Rhode Island	14.1	18.5	3.1%
3	**Wyoming**	6.2	8.1	3.0%
4	California	13.0	16.9	2.9%
5	**Indiana**	7.7	9.9	2.9%
6	Massachusetts	14.3	18.4	2.9%
7	**Kentucky**	6.7	8.6	2.8%
8	South Dakota	7.8	10.0	2.7%
9	**North Dakota**	7.1	8.9	2.5%
10	**Missouri**	7.8	9.7	2.5%
	US average	**9.8**	**10.5**	**0.8%**

Source: Form EIA-861 – Annual Electric Power Industry Report (2010-2019)

7.1.3 Average electricity rates in the region

Electricity prices in Indiana have increased at a CAGR of 2.9% over the ten-year period from 2010 to 2019, slowly eroding the State's comparative advantage of having "cheaper-than-average" energy prices as compared to neighboring states (specifically Illinois, Michigan, and Ohio).[168] The

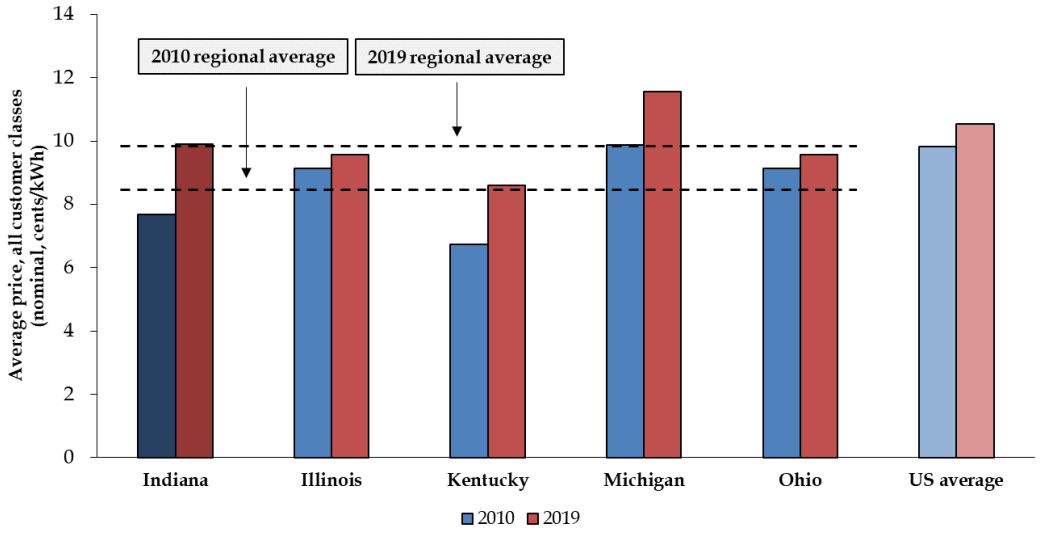
[168] Indiana University. *The Long View: Indiana's Energy Outlook.* Winter 2015.

increase in electricity prices in Indiana can be attributed to several key drivers, including flattening demand, investments in environmental retrofits at fossil fuel-fired plants to meet Federal regulations, and increasing transmission and distribution capital investments.[169] A more detailed discussion of the drivers of electricity costs is found in Section 8.

In 2010, the average electricity price in Indiana was 10% lower than the regional average (comprising Illinois, Indiana, Kentucky, Michigan, and Ohio), at 7.7 cents/kWh compared to the regional average of 8.5 cents/kWh. By 2019, Indiana's average electricity price was slightly higher than the regional average, at 9.9 cents/kWh compared to the regional average of 9.8 cents/kWh. These movements are summarized in Figure 76.

Over the 2010 to 2019 period, electricity prices in Indiana grew at a CAGR of 2.9% on average across all three customer classes, rising faster than the national average inflation rate, which averaged 1.8% (for consumer prices) and 0.8% (for electricity prices) over the same period. As shown in Figure 77, by 2019, the average electricity price for residential customers was 12.6 cents/kWh, compared to 11.0 cents/kWh for commercial customers, and 7.4 cents/kWh for industrial customers.

Figure 76. Average electricity prices in Indiana and neighboring states (2010 versus 2019)

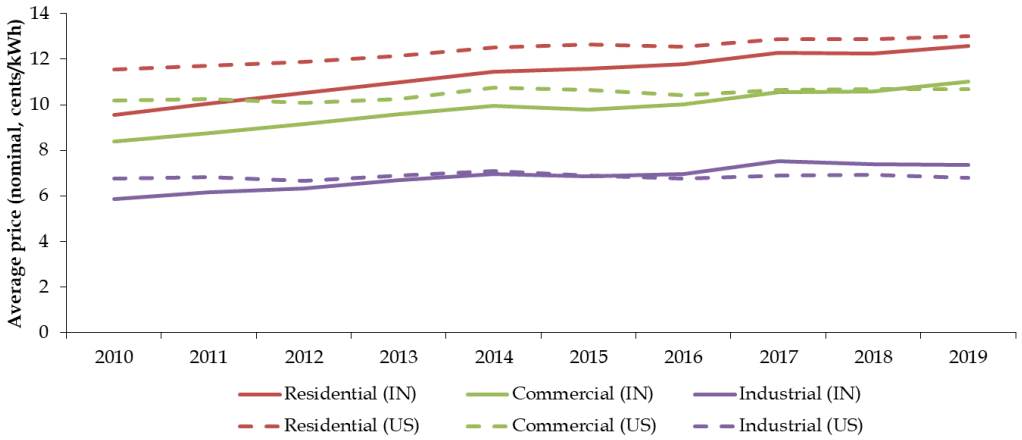


Year	Indiana	Illinois	Kentucky	Michigan	Ohio	Regional average	US average
2010	7.7	9.1	6.7	9.9	9.1	**8.5**	**9.8**
2019	9.9	9.6	8.6	11.6	9.6	**9.8**	**10.5**
CAGR	2.9%	0.5%	2.8%	1.8%	0.5%	**1.6%**	**0.8%**

Source: US EIA. *Average Price by State by Provider, Form EIA-861, Detailed State Data.* 2020.

[169] State Utility Forecasting Group. *Indiana's Changing Generation Mix: Where We Were, Where We Are, and Where We are Going.* Utility Law Section Fall Seminar, Indiana State Bar Association. September 12, 2019. LEI notes that differences in tax treatment of utilities can also drive regional rate disparities.

Figure 77. Average electricity prices in Indiana by customer type (2010-2019)



Year	Residential	Commercial	Industrial	US inflation rate
2010	9.6	8.4	5.9	1.6%
2019	12.6	11.0	7.4	1.8%
CAGR/average	3.1%	3.1%	2.5%	1.8%

Sources: US EIA. *Form EIA-861.* 2020; US FRED. *Inflation, consumer prices for the US.* March 3, 2020.

In the following subsections, we provide a detailed comparison of electricity rates in Indiana (relative to neighboring states, as well as the national average) broken down first by customer class, and then by service provider.

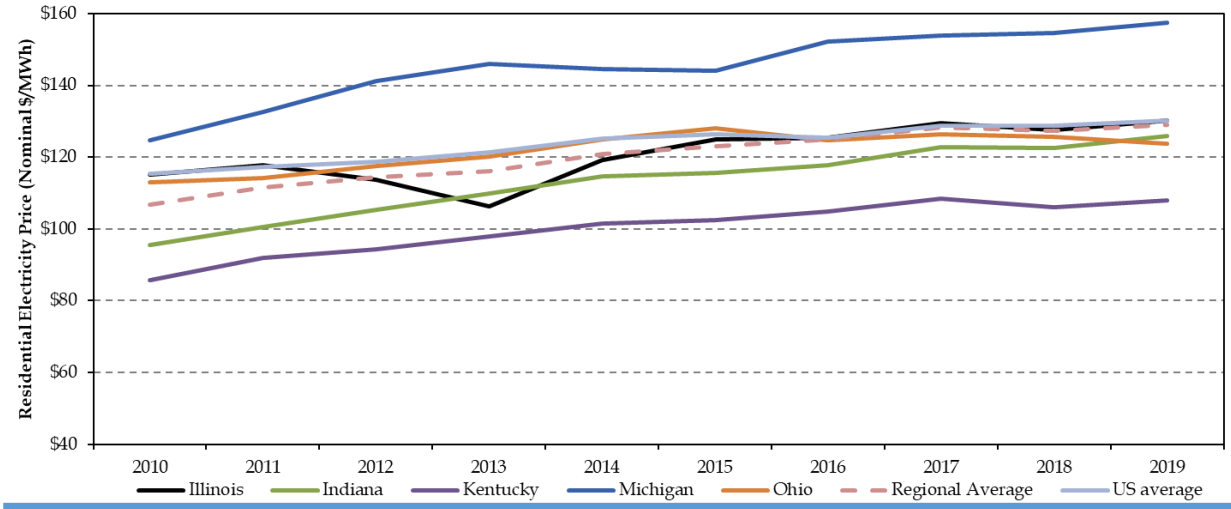
7.1.3.1 Electricity rates by customer class

Electricity rates in Indiana are generally lower than rates in neighboring states, with the exception of Kentucky. Consequently, Indiana's cost of electricity has been lower than the regional average for all years in the period studied except 2019. Moreover, the regional average is lower than the national average.

Residential electricity rates

Average residential electricity rates in Indiana have consistently been the second lowest rates in the region for the past ten years (except in 2013 and 2019, when residential rates in Indiana dropped to third place). Kentucky has the lowest residential rates, while Michigan has the highest residential rates. Indiana's average residential electricity rates are also lower than the regional and national averages (Figure 78). Nevertheless, it is important to note that the growth rate of residential electricity rates in Indiana (3.1% per annum) is higher than the regional and the national average growth rate.

Figure 78. Average residential electricity rates in the region (nominal, $/MWh)



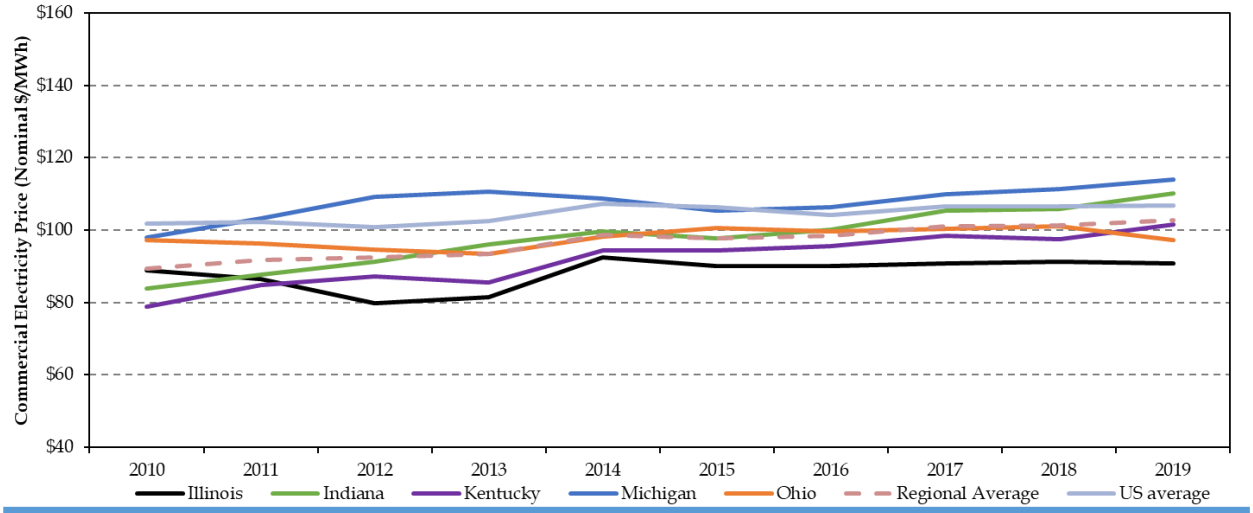
Nominal $/MWh	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	*CAGR*
Illinois	$ 115.2	$ 117.8	$ 113.8	$ 106.3	$ 119.1	$ 125.0	$ 125.4	$ 129.5	$ 127.7	$ 130.3	***1.4%***
Indiana	$ 95.6	$ 100.6	$ 105.3	$ 109.9	$ 114.6	$ 115.7	$ 117.9	$ 122.9	$ 122.6	$ 125.8	***3.1%***
Kentucky	$ 85.7	$ 92.0	$ 94.3	$ 97.9	$ 101.6	$ 102.4	$ 104.9	$ 108.5	$ 106.0	$ 108.0	***2.6%***
Michigan	$ 124.6	$ 132.7	$ 141.3	$ 145.9	$ 144.6	$ 144.2	$ 152.2	$ 154.0	$ 154.5	$ 157.4	***2.6%***
Ohio	$ 113.1	$ 114.2	$ 117.6	$ 120.1	$ 125.0	$ 128.0	$ 124.7	$ 126.3	$ 125.6	$ 123.8	***1.0%***
Regional Average	$ 106.8	$ 111.5	$ 114.5	$ 116.0	$ 121.0	$ 123.1	$ 125.0	$ 128.2	$ 127.3	$ 129.1	***2.1%***
US average	$ 115.4	$ 117.2	$ 118.8	$ 121.3	$ 125.2	$ 126.5	$ 125.5	$ 128.9	$ 128.7	$ 130.1	***1.3%***
Indiana's regional ranking	2	2	2	3	2	2	2	2	2	3	
Indiana's national ranking	17	17	18	21	21	22	24	25	27	31	

Source: Form EIA-861 – Annual Electric Power Industry Report (2010-2019)

Commercial electricity rates

On the other hand, Indiana's average commercial rates were slightly lower than the regional average until 2013, when they overtook the regional average. Compared to the five states considered in this Study, Indiana went from having the second lowest average commercial rates in 2010, to the fourth by 2019. In terms of growth rate, Indiana's average commercial electricity rates have increased by a CAGR of 3.1% from 2010 to 2019, demonstrating the highest growth rate in the region (Figure 79).

Figure 79. Average commercial electricity rates in the region (nominal, $/MWh)



Nominal $/MWh	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	*CAGR*
Illinois	$ 88.8	$ 86.4	$ 79.9	$ 81.4	$ 92.6	$ 90.2	$ 90.2	$ 90.9	$ 91.2	$ 90.8	***0.2%***
Indiana	$ 83.8	$ 87.7	$ 91.4	$ 96.0	$ 99.6	$ 97.8	$ 100.1	$ 105.4	$ 106.0	$ 110.3	***3.1%***
Kentucky	$ 78.8	$ 84.9	$ 87.3	$ 85.6	$ 94.4	$ 94.4	$ 95.7	$ 98.5	$ 97.4	$ 101.5	***2.9%***
Michigan	$ 98.1	$ 103.3	$ 109.3	$ 110.6	$ 108.7	$ 105.5	$ 106.4	$ 110.0	$ 111.5	$ 113.9	***1.7%***
Ohio	$ 97.3	$ 96.3	$ 94.7	$ 93.5	$ 98.3	$ 100.7	$ 99.7	$ 100.5	$ 101.1	$ 97.2	***0.0%***
Regional Average	$ 89.4	$ 91.7	$ 92.5	$ 93.4	$ 98.7	$ 97.7	$ 98.4	$ 101.1	$ 101.4	$ 102.7	***1.6%***
US average	$ 101.9	$ 102.4	$ 100.9	$ 102.6	$ 107.4	$ 106.4	$ 104.3	$ 106.6	$ 106.7	$ 106.8	***0.5%***
Indiana's regional ranking	2	3	3	4	4	3	4	4	4	4	
Indiana's national ranking	18	20	23	26	26	24	29	32	34	37	

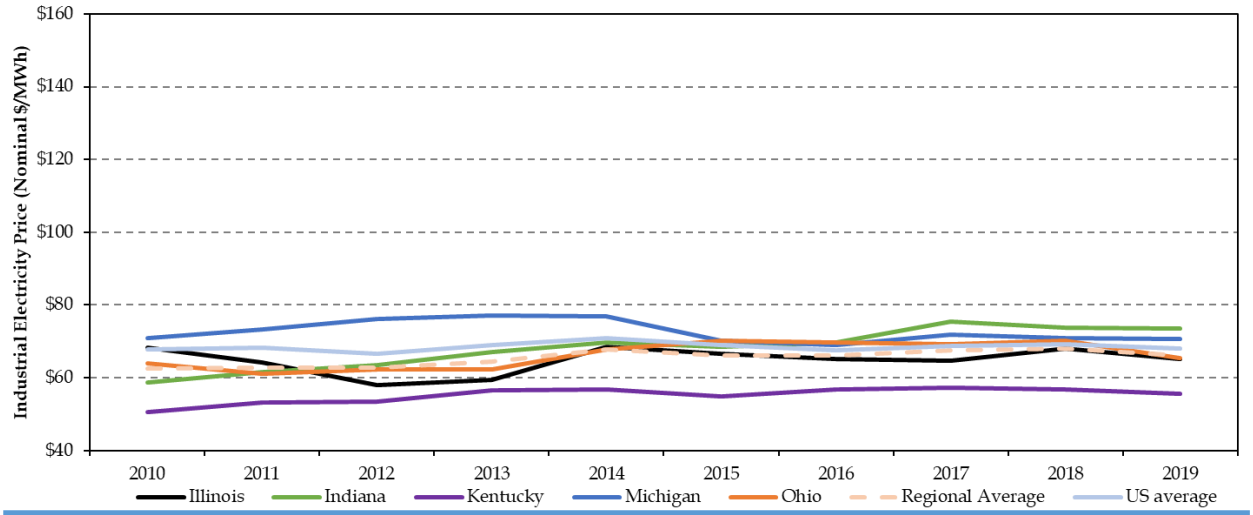
Source: Form EIA-861 – Annual Electric Power Industry Report (2010-2019)

Industrial electricity rates

Indiana had the second lowest average industrial electricity rates in 2010 among the states reviewed, but its position dropped to last in the region starting in 2017. In other words, Indiana had the highest average industrial electricity rates in the region by 2019. Moreover, Indiana's industrial electricity rates have been higher than the regional average since 2012, and higher than the national average from 2016 onwards.

In addition, industrial electricity rates in Indiana have been growing at the highest rate in the region, at a CAGR of 2.5%, relative to other states, whose CAGRs ranged between -0.5% and 1.1% (Figure 80).

Figure 80. Average industrial electricity rates in the region (nominal, $/MWh)



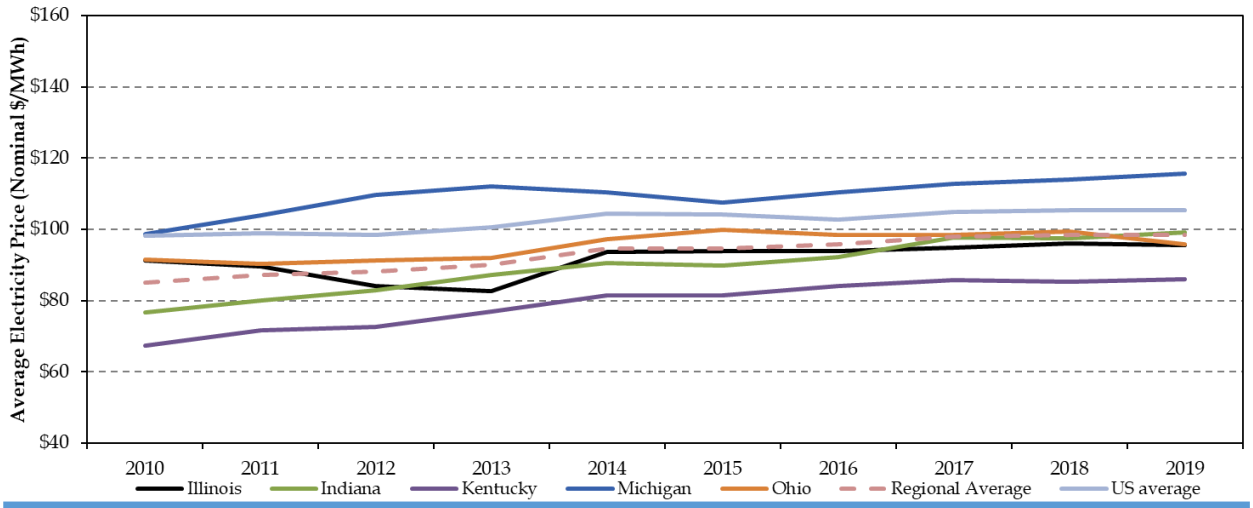
Nominal $/MWh	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	*CAGR*
Illinois	$ 68.2	$ 64.2	$ 58.0	$ 59.4	$ 68.5	$ 66.7	$ 65.1	$ 64.7	$ 68.0	$ 65.2	***-0.5%***
Indiana	$ 58.7	$ 61.7	$ 63.4	$ 67.0	$ 69.7	$ 68.6	$ 69.7	$ 75.4	$ 73.8	$ 73.6	***2.5%***
Kentucky	$ 50.5	$ 53.3	$ 53.5	$ 56.6	$ 56.8	$ 54.8	$ 56.7	$ 57.2	$ 56.8	$ 55.7	***1.1%***
Michigan	$ 70.8	$ 73.2	$ 76.2	$ 77.2	$ 76.8	$ 70.2	$ 69.1	$ 71.9	$ 71.0	$ 70.7	***0.0%***
Ohio	$ 64.0	$ 61.2	$ 62.4	$ 62.2	$ 67.7	$ 70.2	$ 69.8	$ 69.2	$ 70.1	$ 65.5	***0.3%***
Regional Average	$ 62.4	$ 62.7	$ 62.7	$ 64.5	$ 67.9	$ 66.1	$ 66.1	$ 67.7	$ 67.9	$ 66.1	***0.6%***
US average	$ 67.7	$ 68.2	$ 66.7	$ 68.9	$ 71.0	$ 69.1	$ 67.6	$ 68.8	$ 69.2	$ 68.1	***0.1%***
Indiana's regional ranking	2	2	3	4	4	3	4	5	5	5	
Indiana's national ranking	16	17	23	29	28	26	28	33	31	32	

Source: Form EIA-861 – Annual Electric Power Industry Report (2010-2019)

Average electricity rates across all customer classes

In terms of total average electricity rates, Indiana's rates were lower than both the regional and national averages from 2010 to 2019. In 2019, Indiana's rates remained below the national average, but inched slightly above the regional average. Indiana's average electricity rates were the second lowest among the five states in 2010, but slid to fourth place by 2019. Moreover, the growth rate in Indiana's average electricity rates over the period studied was the highest in the region, with a CAGR of 2.9% (Figure 81).

Figure 81. Total average electricity rates in the region (nominal, $/MWh)



Nominal $/MWh	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	CAGR
Illinois	$ 91.3	$ 89.7	$ 84.0	$ 82.6	$ 93.6	$ 94.0	$ 93.8	$ 94.9	$ 96.0	$ 95.6	***0.5%***
Indiana	$ 76.7	$ 80.1	$ 82.9	$ 87.3	$ 90.6	$ 89.9	$ 92.2	$ 97.7	$ 97.5	$ 99.1	***2.9%***
Kentucky	$ 67.3	$ 71.7	$ 72.6	$ 76.9	$ 81.5	$ 81.4	$ 84.2	$ 85.7	$ 85.2	$ 86.1	***2.8%***
Michigan	$ 98.8	$ 104.0	$ 109.8	$ 112.1	$ 110.3	$ 107.6	$ 110.5	$ 112.8	$ 114.0	$ 115.6	***1.8%***
Ohio	$ 91.4	$ 90.3	$ 91.2	$ 92.0	$ 97.3	$ 99.8	$ 98.4	$ 98.4	$ 99.4	$ 95.8	***0.5%***
Regional Average	$ 85.1	$ 87.2	$ 88.1	$ 90.2	$ 94.7	$ 94.5	$ 95.8	$ 97.9	$ 98.4	$ 98.4	***1.6%***
US average	$ 98.3	$ 99.0	$ 98.4	$ 100.7	$ 104.4	$ 104.1	$ 102.7	$ 104.8	$ 105.3	$ 105.4	***0.8%***
Indiana's regional ranking	2	3	3	3	3	2	2	3	3	4	
Indiana's national ranking	13	13	14	15	17	16	20	20	25	28	

Note: Total average electricity rates include residential, commercial, industrial, transportation, and other users of electricity. Rates for individual customers may differ and may be higher for smaller customers within a customer class.

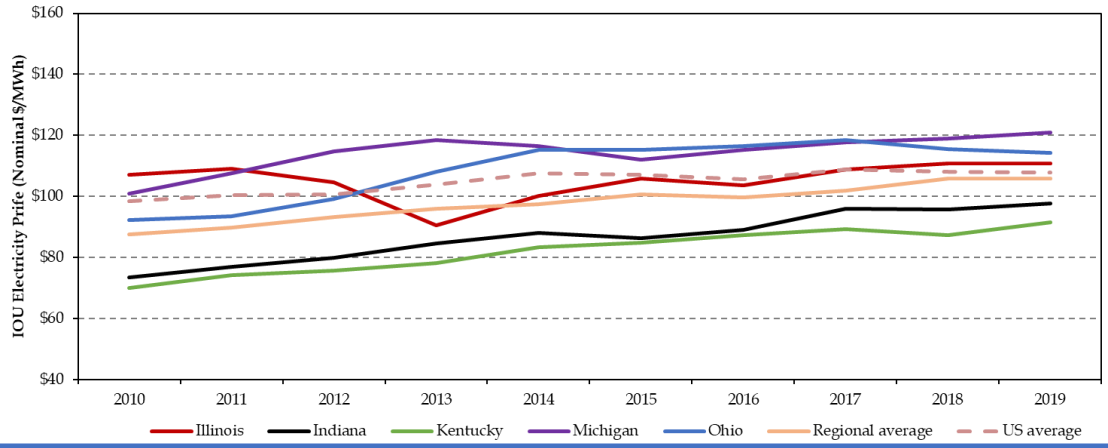
Source: Form EIA-861 – Annual Electric Power Industry Report (2010-2019)

7.1.3.2 Electricity rates by service provider

Looking at the average electricity rates by service provider shows that there is a greater diversity in electricity costs among IOUs and co-ops in the region, while rates charged by munis tend to be more closely clustered (Figure 82 to Figure 84). On average, co-ops had higher average electricity rates than IOUs and munis over the period studied (2010-2019). This does not necessarily reflect inefficiencies or ineffectiveness in their ratemaking practices. Co-ops were originally founded to bring electricity to rural areas that IOUs were formerly reluctant to serve. In general, these areas have a lower number of customers per area (or customer density), which means that more infrastructure investments are needed to reach load centers.

EIA data also shows that Kentucky's IOUs and co-ops had the lowest average electricity rates among the five states in the past ten years, while Michigan had the highest electricity rates in the region. The average electricity rates charged by IOUs and co-ops in Indiana were in the middle of the pack, while munis in Indiana charged the lowest rates in the region. In addition, the average electricity rates of Indiana's IOUs and munis were lower than the regional and national averages in all ten years studied.

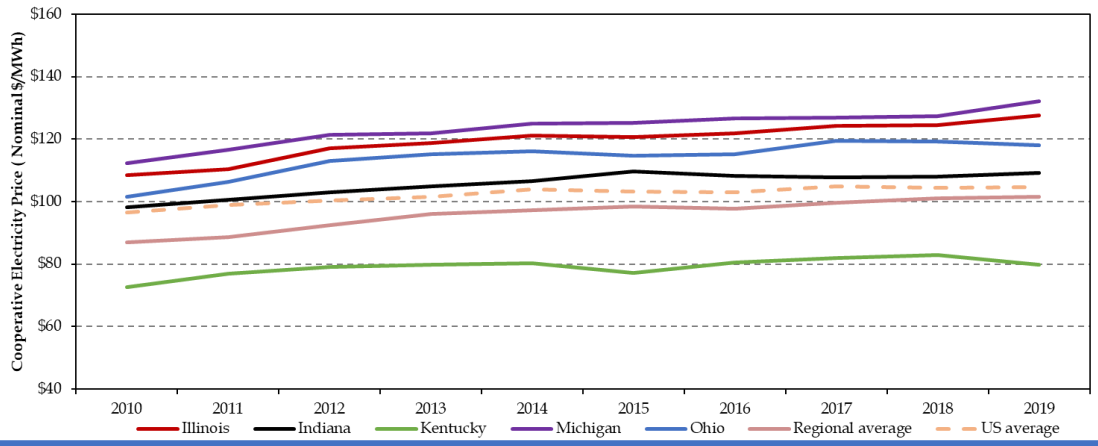
Figure 82. Regional electricity rates (IOUs) (nominal, $/MWh)



Nominal $/MWh	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	*CAGR*
Illinois	$ 107.2	$ 109.1	$ 104.6	$ 90.6	$ 100.2	$ 105.9	$ 103.6	$ 108.7	$ 110.8	$ 110.9	***0.4%***
Indiana	$ 73.4	$ 77.0	$ 79.8	$ 84.5	$ 88.0	$ 86.3	$ 89.1	$ 95.9	$ 95.8	$ 97.7	***3.2%***
Kentucky	$ 70.0	$ 74.2	$ 75.8	$ 78.1	$ 83.3	$ 84.8	$ 87.3	$ 89.2	$ 87.4	$ 91.6	***3.0%***
Michigan	$ 100.9	$ 107.6	$ 114.7	$ 118.5	$ 116.5	$ 112.1	$ 115.2	$ 117.6	$ 119.0	$ 121.1	***2.0%***
Ohio	$ 92.3	$ 93.6	$ 99.1	$ 108.0	$ 115.3	$ 115.3	$ 116.6	$ 118.6	$ 115.6	$ 114.2	***2.4%***
Regional average	$ 87.6	$ 89.8	$ 93.2	$ 95.9	$ 97.4	$ 100.5	$ 99.8	$ 101.9	$ 105.8	$ 105.8	***2.1%***
US average	$ 98.5	$ 100.3	$ 100.6	$ 103.8	$ 107.5	$ 107.1	$ 105.6	$ 108.7	$ 108.2	$ 107.8	***1.0%***

Source: Form EIA-861 – Annual Electric Power Industry Report (2010-2019)

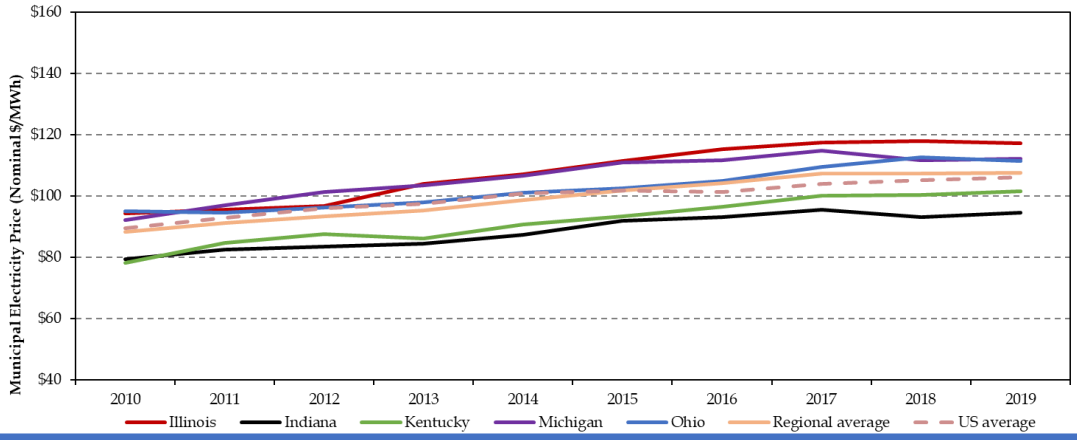
Figure 83. Regional electricity rates (co-ops) (nominal, $/MWh)



Nominal $/MWh	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	*CAGR*
Illinois	$ 108.5	$ 110.4	$ 117.2	$ 118.8	$ 121.1	$ 120.8	$ 121.9	$ 124.3	$ 124.4	$ 127.7	***1.8%***
Indiana	$ 98.3	$ 100.5	$ 103.1	$ 104.9	$ 106.6	$ 109.6	$ 108.1	$ 107.6	$ 107.9	$ 109.2	***1.2%***
Kentucky	$ 72.6	$ 76.8	$ 79.1	$ 79.8	$ 80.3	$ 77.1	$ 80.5	$ 81.9	$ 82.9	$ 79.7	***1.0%***
Michigan	$ 112.3	$ 116.7	$ 121.4	$ 121.9	$ 125.0	$ 125.2	$ 126.6	$ 126.9	$ 127.3	$ 132.1	***1.8%***
Ohio	$ 101.6	$ 106.4	$ 113.1	$ 115.2	$ 116.0	$ 114.6	$ 115.2	$ 119.5	$ 119.2	$ 117.9	***1.7%***
Regional average	$ 86.9	$ 88.7	$ 92.5	$ 96.0	$ 97.2	$ 98.4	$ 97.8	$ 99.7	$ 101.2	$ 101.6	***1.8%***
US average	$ 96.6	$ 98.8	$ 100.3	$ 101.6	$ 104.0	$ 103.3	$ 103.0	$ 104.8	$ 104.5	$ 104.6	***0.9%***

Source: Form EIA-861 – Annual Electric Power Industry Report (2010-2019)

Figure 84. Regional electricity rates (munis) (nominal, $/MWh)

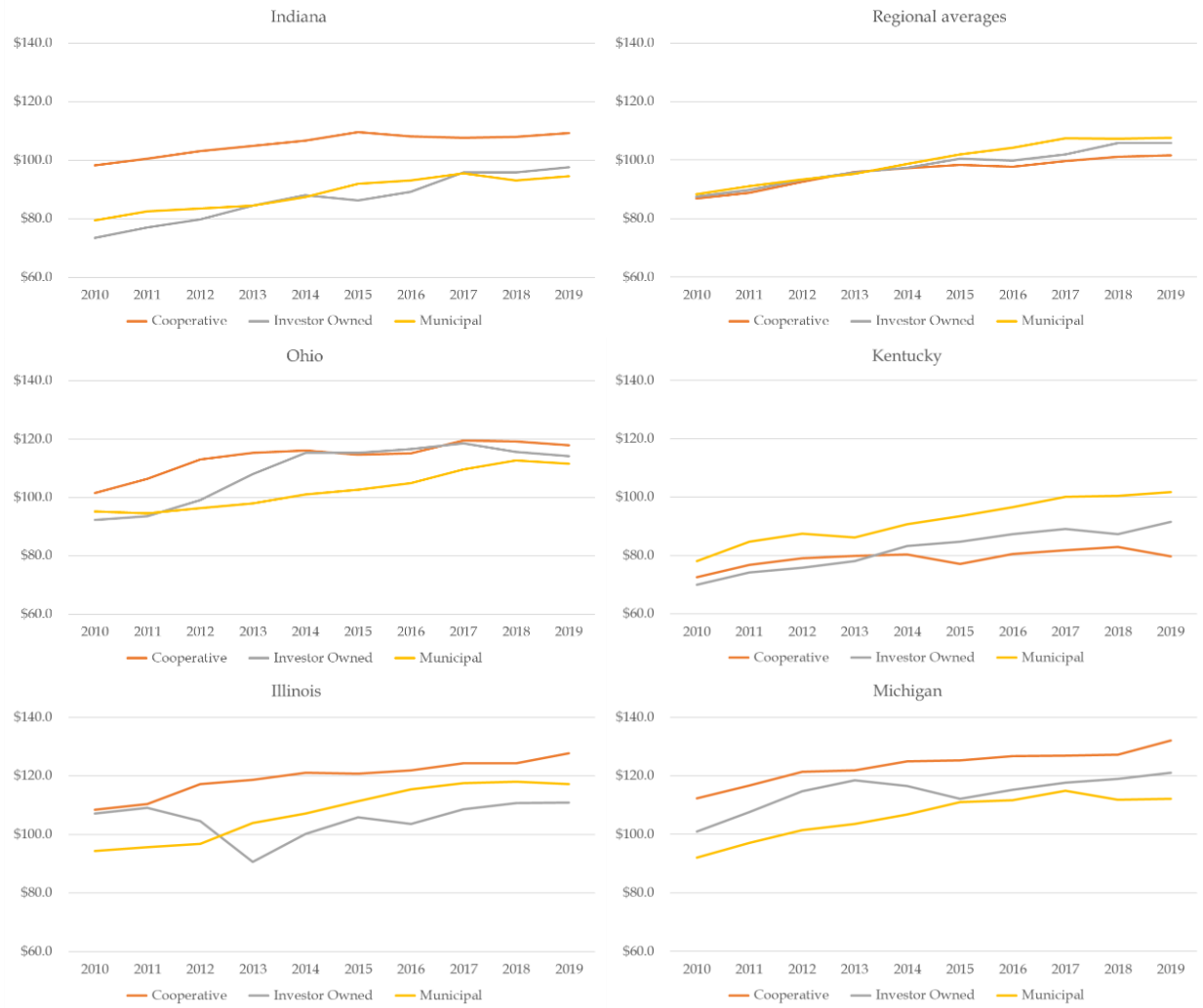


Nominal $/MWh	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	*CAGR*
Illinois	$ 94.3	$ 95.6	$ 96.9	$ 103.9	$ 107.2	$ 111.5	$ 115.4	$ 117.5	$ 118.0	$ 117.3	***2.4%***
Indiana	$ 79.4	$ 82.5	$ 83.5	$ 84.5	$ 87.5	$ 91.9	$ 93.1	$ 95.5	$ 93.1	$ 94.5	***2.0%***
Kentucky	$ 78.2	$ 84.7	$ 87.6	$ 86.3	$ 90.8	$ 93.5	$ 96.6	$ 100.1	$ 100.5	$ 101.7	***3.0%***
Michigan	$ 92.1	$ 97.0	$ 101.4	$ 103.6	$ 106.8	$ 110.9	$ 111.7	$ 114.9	$ 111.8	$ 112.2	***2.2%***
Ohio	$ 95.2	$ 94.6	$ 96.3	$ 97.9	$ 101.1	$ 102.7	$ 104.9	$ 109.5	$ 112.8	$ 111.6	***1.8%***
Regional average	$ 88.3	$ 91.1	$ 93.3	$ 95.3	$ 98.7	$ 101.9	$ 104.1	$ 107.4	$ 107.3	$ 107.6	***2.2%***
US average	$ 89.5	$ 92.9	$ 96.0	$ 97.6	$ 100.9	$ 101.9	$ 101.3	$ 104.0	$ 105.1	$ 106.1	***1.9%***

Source: Form EIA-861 – Annual Electric Power Industry Report (2010-2019)

The regional average electricity rates by provider type (weighted by individual utility sales volumes) suggest a convergence of electricity rates supplied by co-ops, IOUs, and munis (Figure 85). However, individual states in the region exhibit greater differences in electricity rates. For example, in most states in the region, electricity rates charged by co-ops are higher than the other two types of providers, except in the case of Kentucky, where munis have the highest electricity rates.

Figure 85. Electricity rates by service provider type in the region (nominal, $/MWh)



Source: Form EIA-861- Table 10 (2010-2019)

7.1.4 Affordability

LEI used three metrics to evaluate energy affordability in Indiana as well as its neighboring states. These metrics include the home energy affordability gap ("HEAG"), the home energy burden for low-income households as a percentage of gross income, and the average percentage of households facing unaffordable energy bills. Due to limited data availability, energy affordability was only compared against the national average for the HEAG metric. Analysis of each of the three metrics is discussed in this subsection.

The HEAG is used to quantify the difference, or gap, between economically 'affordable' and actual home energy bills for low-income households. The HEAG is used by many government agencies and organizations to measure energy affordability. These entities include: the American Council for an Energy-Efficient Economy, New York State Energy Research Development

Authority, Pennsylvania Public Utilities Commission, Operation Fuel, and Coalition to Keep Indiana Warm,[170] to name a few. The HEAG is also used by state development authorities interested in quantifying energy affordability within their districts.[171] These metrics are publicly available and compiled by FSC.

The affordability gap is the difference between the ***actual*** home energy bills and the ***affordable*** home energy bills. Factors such as residential energy prices, energy use intensities (by fuel and end-use), tenure of household (owner/renter), housing unit size, heating fuel mix, heating degree days, and cooling degree days determine the ***actual*** home energy bills. An ***affordable burden*** for energy is considered to be 6% of gross household income, with an additional 2% for heating and cooling.[172] The model uses the American Community Survey ("ACS") as the source for demographic information, and aggregates the county-level gaps for each state based on income brackets. The model considers any household earning at or below 200% of the Federal Poverty Level ("FPL") as low-income.[173] The FPL is the income level below which a household is considered to be in poverty, as recorded by the US Department of Health and Human Services. The FPL is adjusted annually for inflation by the Census Bureau and depends on a household's family size. For 2020, the FPL was set at a modified adjusted gross income ("MAGI") of $12,760 for individuals, increasing incrementally to $44,120 for a family of 8.[174] This income includes all forms of income, such as earnings, unemployment compensation, social security payments, and public assistance. The official poverty thresholds do not vary geographically.[175]

Among the five states reviewed in this Study, Michigan consistently had the largest affordability gap over the 2012-2019 period (Figure 86). Indiana's affordability gap has been lower than the regional average for all years examined except 2015. However, Indiana's position has dropped from having the 3rd lowest HEAG in 2012 to the 4th by 2019. On average, Illinois had the lowest affordability gap in the region for the period reviewed (2012-2019). Relative to the national average, Indiana's affordability gap had been lower until 2016; from 2017 onwards, Indiana has reported an affordability gap greater than the national average.

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[170] Colton, R. D. (2009). *Home Energy Affordability in Indiana.* Belmont, Massachusetts.

[171] Colton, R. D. (2012). *Home Energy Affordability in New York.* Albany, New York: New York State Energy Research Development Authority (NYSERDA). Retrieved from https://www.nyserda.ny.gov/-/media/Files/EDPPP/LIFE/Resources/2011-affordability-gap.pdf

[172] The model does not consider state financial resources for energy bill assistance or utility-specific rate discounts.

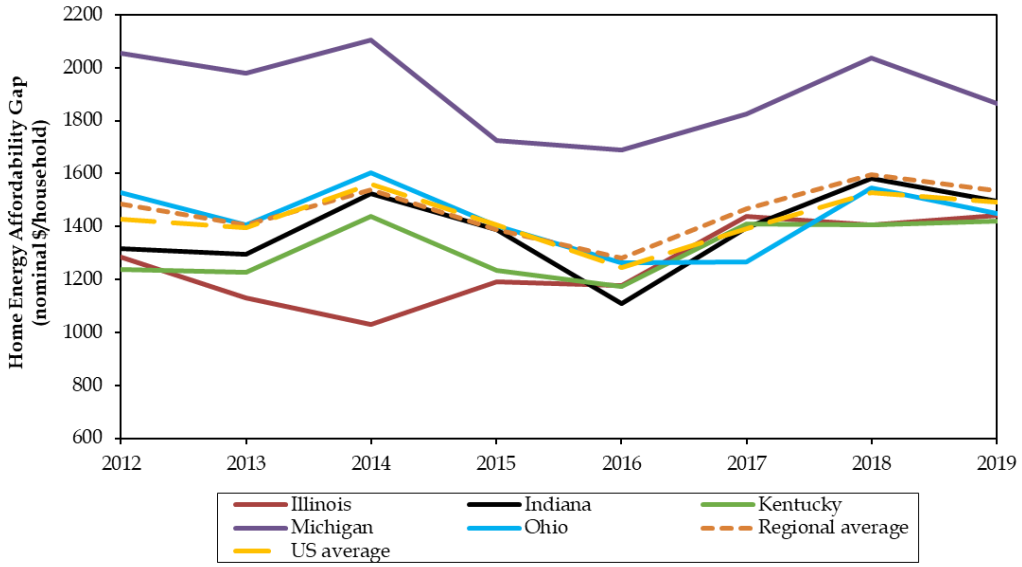
[173] Note that the methodology changed significantly between HEAG analysis done before and after 2011. There was also a change in the definition of low-income, that is, from less than 185% of the FPL to less than 200% of the FPL. Therefore, only data after 2011 can be compared meaningfully.

[174] United States Census Bureau. (2019, August 27). *How the Census Bureau Measure Poverty*. Retrieved from Census: https://www.census.gov/topics/income-poverty/poverty/guidance/poverty-measures.html

[175] Ibid.

According to the FSC, the HEAG is not solely a function of household income and fuel prices, but is also impacted by the extent to which low-income households use each fuel.[176] Therefore, the affordability gap is greater in areas where households use more expensive fuels.

Figure 86. Home energy affordability gap in the region (2012-2019) (nominal, $/household)



	2012	2013	2014	2015	2016	2017	2018	2019
Illinois	$ 1,285	$ 1,129	$ 1,029	$ 1,190	$ 1,176	$ 1,437	$ 1,406	$ 1,441
Indiana	$ 1,318	$ 1,297	$ 1,526	$ 1,390	$ 1,108	$ 1,394	$ 1,582	$ 1,497
Kentucky	$ 1,237	$ 1,229	$ 1,439	$ 1,235	$ 1,173	$ 1,411	$ 1,405	$ 1,422
Michigan	$ 2,055	$ 1,979	$ 2,104	$ 1,726	$ 1,690	$ 1,826	$ 2,038	$ 1,864
Ohio	$ 1,527	$ 1,407	$ 1,603	$ 1,402	$ 1,264	$ 1,265	$ 1,546	$ 1,449
Regional average	$ 1,484	$ 1,408	$ 1,540	$ 1,389	$ 1,282	$ 1,467	$ 1,595	$ 1,535
US average	$ 1,429	$ 1,395	$ 1,559	$ 1,406	$ 1,246	$ 1,393	$ 1,530	$ 1,491
Indiana's regional ranking	3	3	3	3	1	2	4	4

Note: Data represents the average dollar amount by which actual home energy bills exceeded affordable home energy bills for households **below 150%** of FPL.

Source: Fisher Sheehan & Colton. *Home Energy Affordability Gap*.

LEI considered two other measures of affordability, namely the **home energy burden for low-income households as a percentage of gross income** and the **average percentage of households facing unaffordable energy bills**. Both produced similar outcomes. For the first measure, over the 2012-2019 period, Indiana households with income below 50% of the FPL spent, on average, 30% of their annual income on their home energy bills. This is a slightly lower home energy burden as compared to the regional average (31%, 2012-2019). For the second measure, 7.9% of households in Indiana with an income between 50-100% of the FPL faced unaffordable energy

[176] Fisher, Sheehan & Colton. The Home Energy Affordability Gap 2018. April 2019. P. 4.

bills (2012-2018). This again is slightly lower than the regional average (8.5% of households in the 50-100% FPL income bracket, 2012-2018).

Throughout the period studied, Indiana has generally placed in the middle of the pack in terms of energy affordability in the region. Across all three metrics (i.e., the affordability gap, energy burden, and proportion of households facing unaffordable bills), Indiana ranked 3rd in the region. Compared to the US as a whole, Indiana has been relatively on par with the national HEAG average over the 2012-2019 period. However, since 2017, Indiana has reported an affordability gap above the national average.

7.1.5 Reliability

LEI used three metrics to measure the reliability of IOUs in Indiana relative to the national average. These metrics include the SAIDI, SAIFI, and CAIDI:[177]

- **System Average Interruption Duration Index ("SAIDI")** measures the average total number of minutes that a customer is without electricity per year, excluding momentary interruptions. SAIDI is also interpreted as the sum of the restoration time needed per interruption event, multiplied by the number of customers affected by each event, and divided by the total number of customers;
- **System Average Interruption Frequency Index ("SAIFI")** measures the average number of times that a customer has been interrupted from electricity consumption in a year, excluding momentary interruptions. The SAIFI is calculated by considering the total number of customer interruptions divided by the total number of customers served; and
- **Customer Average Interruption Duration Index ("CAIDI")** indicates the average duration of the interruption, measured in minutes, that a customer faces. The CAIDI is estimated by dividing the SAIDI (sum of customer interruption durations) by SAIFI (sum of number of customer interruptions).

LEI compared the customer-weighted average reliability ratings for the five IOUs in Indiana (blue bars in Figure 87) with the customer-weighted national average (red bars) for IOUs across the country over the 2017-2019 period. EIA data only includes IOUs that submit the Form 861. As such, the national average presented in Figure 87 comprises of data from 141 IOUs (across 48 states), including the five IOUs in Indiana. For all three reliability metrics discussed below, a lower number is better.

As demonstrated in the charts, the customer-weighted average **SAIDI** in Indiana was 148.9 minutes for the 2017-2019 period, higher than the national average of 122.5 minutes. This means that IOUs in Indiana in aggregate[178] had a higher interruption duration index than the average IOU in the US. As for the **SAIFI**, customers of Indiana IOUs in aggregate experienced on average

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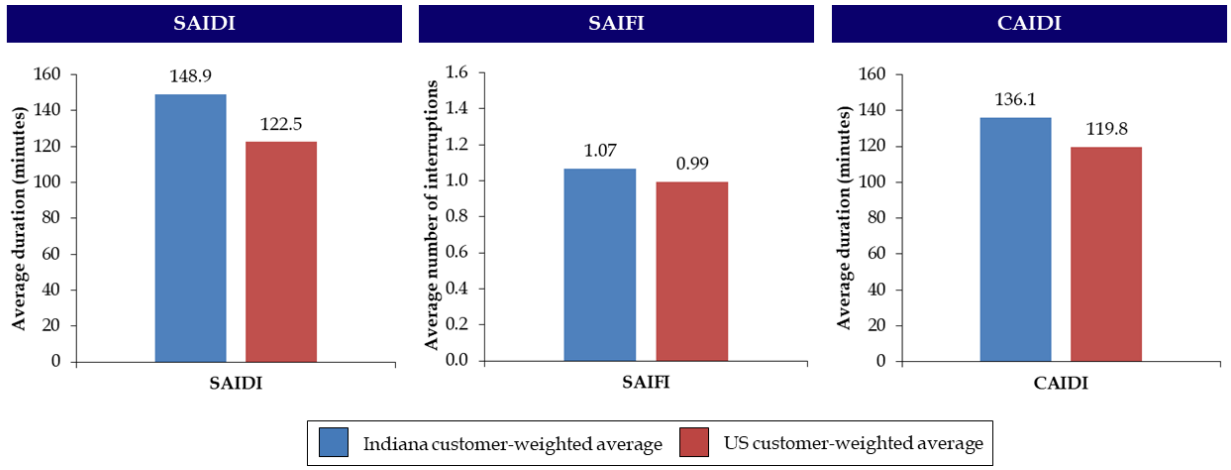
[177] IEEE. *IEEE 1366 – Reliability Indices*. February 19, 2019. < http://site.ieee.org/boston-pes/files/2019/03/IEEE-1366-Reliability-Indices-2-2019.pdf>

[178] Results for individual utilities in Indiana differ; calculations are customer-weighted averages and are intended to reflect the experience of Indiana customers collectively.

1.07 interruptions per year over the period, compared to the national average of 0.99 interruptions per year. Finally for **CAIDI**, customers of Indiana IOUs in aggregate experienced longer outages than the customer-weighted national average (136.1 minutes per year versus 119.8 minutes per year, respectively). It is important to note that all of these differences were greater than one standard deviation from the customer-weighted national average.

Figure 87. Customer-weighted average SAIDI, SAIFI, CAIDI for IOUs in Indiana versus the US average (2017-2019)



Note: IEEE Standard SAIDI/SAIFI/CAIDI without Major Event Days. National customer-weighted average comprises of 141 IOUs, including the five IOUs in Indiana.

Source: EIA Annual Electric Power Industry Report, Form EIA 861; IURC Electric Utility Reliability Report 2019.

LEI also compared the reliability performance of each of the five Indiana IOUs to the IOUs in the region. We have aggregated this analysis to the state-level and include a discussion of this analysis in Section 7.2 below.

7.2 Ranking based on costs, affordability, and reliability

This section ranks the five states in the region based on their average electricity rates, affordability, and reliability, as discussed throughout the previous sections. We also compare the states in terms of their national ranking for further context. The relative regional rankings are determined as follows:

- **electricity rates:** a state is ranked higher if it has lower electricity rates, and vice versa. To rank the states, LEI looked at the average electricity rates for the past ten years (2010-2019) by customer type (i.e., residential, commercial, industrial), as well as averaged across all customer classes. Each customer type is given an equal ranking;
- **affordability:** a state is ranked higher in terms of energy affordability if it has a lower affordability gap and energy burden, and if the average percentage of households facing unaffordable energy bills is lower; and
- **reliability:** the reliability ranking is based on IOU performance as measured through the SAIDI, SAIFI, and CAIDI. State performance is compared with the regional average,

where the number of IOUs that performed well (i.e., those whose average fell below the regional average) is measured against the total number of IOUs in the state. The higher the percentage (or, the more IOUs with better reliability performance relative to the regional average), the higher the ranking.

In terms of average electricity rates, Kentucky ranked first among the five states. It had the lowest average residential, industrial, and total electricity rates for the period studied (Figure 88). Illinois ranked second, followed by Indiana (3rd), Ohio (4th), and Michigan (5th). Notably, Michigan had the highest average electricity rates across all customer classes. In terms of their national rankings for 2019 (system-wide), Kentucky ranked 10th, followed by Illinois (21st), Indiana (28th), Ohio (22nd), and Michigan (39th).

Figure 88. Ranking of the five states in terms of average electricity rates (2010-2019)

State	Electricity rates				Regional ranking	National ranking (2019)
	Residential	Commercial	Industrial	System-wide		
Illinois	3	1	2	3	2	21
Indiana	2	3	4	2	3	28
Kentucky	1	2	1	1	1	10
Michigan	5	5	5	5	5	39
Ohio	4	4	3	4	4	22

Illinois ranked first in terms of energy affordability (Figure 89). It had the lowest affordability gap, energy burden, and percentage of households facing unaffordable bills. Across all three metrics, Indiana tied with Kentucky in second place; while Indiana ranked third in all three parameters, Kentucky ranked second in both the affordability gap and energy burden, but last in the percentage of unaffordable bills. Michigan ranked last among the five states, with the highest affordability gap and energy burden.

The table also lists each state in the region relative to the national HEAG average for 2019. Both Indiana and Michigan had higher affordability gaps than the national average, although Indiana's was only $5 higher, while Michigan's was $373 higher. In contrast, Illinois, Kentucky, and Ohio all fare better than the national HEAG average in terms of energy affordability.

Figure 89. Ranking of the five states in terms of energy affordability (2012-2019)

State	Affordability			Regional ranking	Relative to national HEAG average (2019)
	Affordability gap	Energy burden	Unaffordable bills		
Illinois	1	1	1	1	Better (-$50)
Indiana	3	3	3	2.5	Worse ($5)
Kentucky	2	2	5	2.5	Better (-$69)
Michigan	5	5	4	5	Worse ($373)
Ohio	4	4	2	4	Better (-$42)

In terms of reliability, Illinois ranked first, as all the IOUs included in the Study had below average SAIDI, SAIFI, and CAIDI. In contrast, Michigan ranked last. Indiana ranked fourth because some of the IOUs' SAIDI, SAIFI, and CAIDI tracked above the regional average (i.e., the frequency and duration of outages were higher than the regional average, but were notably within one standard deviation) (Figure 90). Compared to the national averages for all three metrics, IOUs in Indiana performed worse on a customer-weighted basis (as discussed in Section 7.1.5).

Figure 90. Ranking of the five states in terms of reliability (3-year average 2017-2019)

State	Reliability			Regional ranking
	SAIDI	SAIFI	CAIDI	
Illinois	1	1	1	1
Indiana	4	5	4	4
Kentucky	3	2	3	3
Michigan	5	4	5	5
Ohio	2	3	2	2

Key takeaways

- Electricity prices in the state have risen continuously in the last decade, eroding Indiana's comparative price advantage relative to neighboring states (specifically Illinois, Michigan, and Ohio) and the rest of the nation (in 2010, Indiana ranked among the top half cheapest states, by 2019, Indiana dropped to the bottom half). Although Indiana's electricity rates were relatively lower than the regional average in most of the years reviewed, its ranking has dropped over the past 10 years. The CAGRs of Indiana's residential, commercial, and industrial electricity rates from 2010 to 2019 were also the highest among the region.
- Indiana's affordability gap has been lower than the regional average for all years studied (2012-2019) except 2015. However, since 2017, the State's affordability gap has been higher than the national average. As another measure of affordability, households in Indiana with incomes below 50% of the Federal poverty level spent, on average, 30% of their annual income on their home energy bills (2012-2019).
- IOUs in Indiana generally demonstrated poorer reliability performance than the regional and national averages. The differences in performance were within one standard deviation of the regional average, but greater than one standard deviation from the national average.
- Overall, average electricity rates in Indiana are growing more rapidly than the national average, affordability is declining, and reliability is lower than national norms.

8 Factors that have driven cost changes

Electricity prices in Indiana have increased at a CAGR of 2.9% over the ten-year period from 2010 to 2019 (rising at a CAGR of 3.1% for residential and commercial customers, and 2.5% for industrial customers), as discussed in Section 7. LEI forecasts these prices could increase at a CAGR of 2% over the next ten years, as covered in Section **8.5**. The following chapter explores the factors that have driven electricity costs up in Indiana historically, as well as the factors that could continue to impact costs moving forward. We include a discussion of how these cost drivers are impacting neighboring states and highlight the additional cost drivers that are unique to each of these jurisdictions (Illinois, Kentucky, Michigan, and Ohio).

8.1 Historical drivers identified in rate cases

To provide an understanding of the factors that have driven electricity costs upward in Indiana over the past ten years, LEI has reviewed regulatory rate cases and decisions before the IURC to identify cost drivers as cited by the regulated utilities. Generally, and as corroborated by the IURC, Indiana's dependence on coal as a primary fuel source has historically contributed to the State's relatively low-cost electricity, however, "investment costs to address environmental mandates, the general trending of increased coal prices, decreasing natural gas prices, and the replacement of aging infrastructure have reduced Indiana's relative price advantage."[179]

A number of drivers have contributed to increases in Indiana's electricity prices over the past decade, including:[180]

(1) flattening/low demand;

(2) a growing need to replace and maintain aging infrastructure; and

(3) investments in environmental retrofits at fossil fuel plants needed to meet tightening Federal regulations.

These three drivers are explored in subsections 8.1.1 to 8.1.3 below.

8.1.1 Flattening demand

As discussed in Section 5.2.3, total electricity sales in Indiana have flattened over the past ten years, declining at a CAGR of -0.4% from 2010-2019. This growth rate is down from the previous ten-year period (2000-2009), where electricity sales in Indiana grew at a CAGR 0.2%. As a result of this decline in load, we estimate that rates are approximately 0.5 cents/kWh higher than they would have been if load growth continued at the 2000-2009 level (CAGR of 0.2%).[181]

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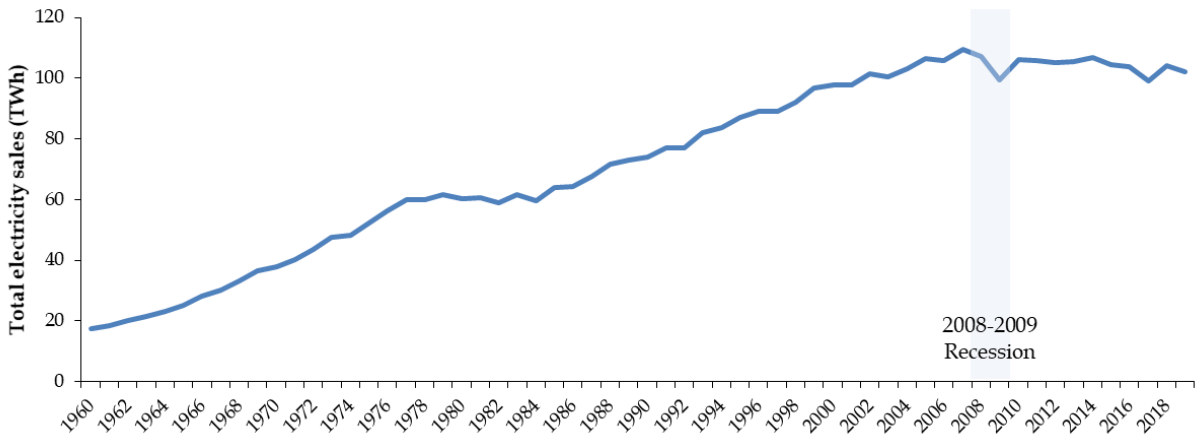
[179] Indiana Utility Regulatory Commission. *2019 Annual Report.* 2019.

[180] Indiana Utility Regulatory Commission. *Indiana Utility Guide.* 2019 Edition.

[181] To determine this, we first calculated the missing load resulting from the slowing load growth, by growing electricity sales by 0.2% per annum as opposed to declining by -0.4%. We then multiplied actual 2019 electricity sales by

Figure 91 illustrates the flattening trend in Indiana's load growth, with additional context provided over an extended time horizon (1960-2019 – i.e., going as far back as EIA data is available). Electricity sales dipped noticeably around the 2008-2009 global financial crisis, and growth has flattened since.

Figure 91. Total electricity sales in Indiana, 1960-2019



Sources: US EIA. *Retail Sales of Electricity by State by Sector by Provider, Form EIA-861, Detailed State Data.* 2020.

Flattening electricity demand in Indiana has been driven by numerous factors, including but not limited to:

- declining customer usage as a result of **increasing energy efficiency** efforts, both from the increased use of efficient appliances and the implementation of utility efficiency programs.[182] Despite the rollback of the State's energy efficiency standard in 2014 (see Section 5.3.2), utilities have continued to offer efficiency programs to their customers. As such, over the 2009-2018 period, electricity savings as a percent of total sales climbed from 0.04% to 0.55% in Indiana;[183]

the average electricity rate for the year (9.9 cents/kWh). Finally, we divided this total by the higher load level estimated for 2019 (based on the 0.2% growth rate) – resulting in an electricity rate of 9.4 cents/kWh.

[182] Ibid.

[183] American Council for an Energy-Efficient Economy. *State Energy Efficiency Scorecard.* 2011 and 2019 reports.

- **declining electricity intensity**, which is a measure of electricity use per square foot of floor space. Electricity intensity has fallen, particularly among commercial customers in Indiana, from a high of growing by 4.7% per year over the 1965-1974 period to declining by -2.3% per year over the 2005-2017 period.[184] This has been driven by improvements in building and equipment efficiencies, as well as changes in equipment utilization; and

> **Electricity intensity:** a ratio of electricity consumption to another metric. Sector-specific intensities may refer to electricity consumption per household, per unit of commercial floorspace, per dollar value industrial shipment, or another metric indicative of a sector.
>
> Source: EIA.

- **modest manufacturing output**, declining from a growth rate of 3.3% per year (1965-1974) to 1.0% per year (2005-2017), which has greatly impacted industrial load.[185] The manufacturing sector is an integral part of Indiana's economy, contributing 27.8% to the Gross State Product and employing 17.2% of Indiana's workforce in 2018. As such, changes to manufacturing output have a substantial impact on the State's overall electricity demand.[186]

Given the high fixed cost nature of the electricity industry, all other things being equal, a decrease in electricity use per customer without an increase in the customer base translates to higher rates, because there is a reduction in load over which to spread the fixed costs incurred to generate and deliver electricity.[187] The IURC reiterated this issue of flattening demand in its 2019 Indiana Utility Guide, highlighting that this is especially a concern among smaller utilities in Indiana that primarily serve commercial and industrial customers, whereby the loss of one large customer would shift the burden to the utility's remaining customers.[188]

> *"Due to the fixed nature of many costs of providing electricity service, reductions in sales volumes can have a significant impact to revenues, earnings, and other customers' rates."*
>
> - IURC. *Cause No. 45159.* December 4, 2019. p. 10.

8.1.2 Aging infrastructure

According to the IURC, "[a]ging infrastructure is one of the most critical issues in the utility industry today because it is costly to replace infrastructure."[189] The textbox below highlights excerpts from some recent rate cases where Indiana utilities have cited investments to replace and maintain aging infrastructure as reasons behind increasing rates.

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[184] State Utility Forecasting Group for the IURC. *Indiana Electricity Projections: The 2019 Forecast.* November 2019.

[185] Ibid.

[186] National Association of Manufacturers. *2019 Indiana Manufacturing Facts.*

[187] Indiana Utility Regulatory Commission. *Indiana Utility Guide.* 2019 Edition.

[188] Ibid. p. 24.

[189] Indiana Utility Regulatory Commission. *Indiana Utility Guide.* 2019 Edition. p. 25.

Rate applications citing capital investments to replace aging infrastructure

In NIPSCO's rate application filed in October 2015, the utility requested a rate increase in part because it "has and must continue to make significant capital expenditures for additions, replacements and improvements to its Utility Property, both as a result of environmental mandates and to maintain safe and reliable service." (p. 9)

These sentiments were reiterated in IPL's rate application filed in December 2017, which cited "approximately $2.1 billion in additions, replacements and improvements to used and useful electric utility property." These investments included "major projects" such as environmental compliance projects approved by the IURC, the costs of IPL's 671 MW Eagle Valley CCGT project, and the refueling of the utility's Harding Street Station, as well as "significant capital expenditures to maintain and modernize the transmission, distribution and other facilities used and useful in the provision of adequate and reliable retail electric service." (p. 7)

Finally, in I&M's rate application filed in May 2019, the utility stated it "must continue to invest in modernizing its infrastructure and service offerings to address rapid technological change and evolving customer expectations." (p. 7) Given that much of I&M's system was built in the 1960s and 1970s, "an increasing portion of assets are now reaching the end of their expected design lives." (Exhibit B, p. 17) As such, through I&M's Distribution Management Plan, the utility continues to make substantial investments in its distribution system under its Asset Renewal and Reliability program and its Grid Modernization Projects.

Sources: IURC. *Cause No. 44688*. October 1, 2015; IURC. *Cause No. 45029*. December 21, 2017; IURC. *Cause No. 45235*. May 14, 2019.

Investments in aging infrastructure have, in large part, been incentivized through Indiana's Transmission, Distribution, and Storage System Improvement Charge ("TDSIC").[190] The TDSIC tracker was introduced by the state legislature in 2013 (IC 8-1-39), and provides for automatic rate increases every six months through a rider to recover 80% of approved costs as they are incurred, with the other 20% deferred[191] for recovery in the next rate case.[192] These rate increases are capped at no more than 2% of a utility's total retail revenues.[193] According to the IURC, the TDSIC is a

[190] In 2011, the Illinois General Assembly passed similar legislation, the *Energy Infrastructure Modernization Act*. The law authorized one of the State's utilities (Commonwealth Edison Company, serving approximately 70% of the State's population) to implement a 10-year, $2.6 billion investment program "to strengthen the existing electric system, while adding new digital smart technology." Notably, the law was passed after the Assembly overrode then Illinois Governor Pat Quinn's veto. Governor Quinn stated it "represents a drastic departure from a long tradition of Illinois laws protecting consumers against high energy bills" and would force ratepayers "to pay billions in rate hikes." (Sources: Office of the Governor. *SB1652 Veto Message.* September 12, 2011; PR Newswire. *Illinois General Assembly Enacts Energy Infrastructure Modernization Act.* October 2011).

[191] Encompasses deferral of the 20% of approved capex and TDSIC costs, including depreciation, allowance for funds used during construction, and post in service carrying costs.

[192] Indiana Code § 8-1-39-9.

[193] Indiana Office of Utility Consumer Counselor. *Duke Energy Infrastructure Plan*. January 9, 2020.

rate adjustment mechanism that "covers projects related to safety, reliability, system modernization, and economic development," such as "investments in substations, circuits, underground cables, and breakers/transformers."[194] Through adjustments signed into law in 2019, utilities may submit TDSIC plans for time horizons extending out between five to seven years.[195]

Figure 92 summarizes current TDSIC plans, which total $4.3 billion in approved investments. On average, the total approved amounts represent 28.7% of each utility's rate base, as reported in their most recent base rate cases. Although the plans cover a wide-ranging period, from 2016 to as far out as 2026, around $1.2 billion in capex have already been approved and passed on to ratepayers. Costs associated with these and future TDSIC plans will continue to place upward pressure on electricity prices going forward. Section 8.1.4 discusses the contribution of the TDSIC tracker to historical rates since its introduction.

Figure 92. Approved TDSIC plans by utility

Utility	Plan period	Total amount approved	Approved investments to date	% of approved amount in rates	Total amount as % of utility's rate base
Duke	2016-2022	$1,408,300,000	$506,652,101	36.0%	13.8%
NIPSCO	2016-2022	$1,251,954,035	$500,864,670	40.0%	30.4%
Vectren	2017-2023	$446,508,000	$152,318,962	34.1%	34.3%
IPL	2020-2026	$1,218,454,910	-	-	36.2%
		$4,325,216,945	**$1,159,835,733**	**26.8%**	**28.7%**

Sources: IURC. *2020 Annual Report.* 2020; IURC. *Cause No. 44720.* June 29, 2016; IURC. *Cause No. 44733.* July 12, 2016; IURC. *Cause No. 44910.* September 20, 2017; IURC. *Cause No. 45264.* March 4, 2020; third party commercial database.

8.1.3 Environmental retrofits

According to the IURC, "[t]he impact of federal environmental regulations is greater in Indiana than in most other states because of Indiana's historical use of coal."[196] These Federal regulations include, but are not limited to:

- the **Cross State Air Pollution Rule** ("CSAPR"): finalized by the US EPA in 2011, the rule aims to "improve air quality by reducing power plant emissions that cross state lines and contribute to smog and soot pollution in downwind states."[197] The rule took effect starting January 1st, 2015 for sulfur dioxide ("SO_2") and annual nitrogen oxide ("NO_x") reductions, and May 1st, 2017 for ozone season NO_x reductions;[198]

[194] Indiana Utility Regulatory Commission. *2019 Annual Report.* 2019. p. 28.

[195] Ibid.

[196] Ibid. p. 36.

[197] US EPA. *Overview of the Cross-State Air Pollution Rule (CSAPR).*

[198] Ibid.

- the **Mercury and Air Toxics Standards** ("MATS"): announced by the EPA in 2011, the standards limit mercury, acid gases, and other toxic pollution from coal- and oil-fired power plants through the installation of widely available pollution control equipment;[199]
- the **Affordable Clean Energy** ("ACE") rule: issued by the EPA in 2019 to replace the Clean Power Plan, the rule "establishes emission guidelines for states to use when developing plans to limit carbon dioxide ("CO_2") at their coal-fired electric generating units";[200]
- the **Disposal of Coal Combustion Residuals** ("CCRs") **from Electric Utilities** rule: published in the Federal Register in 2015, the rule promulgated "national regulations to provide a comprehensive set of requirements for the safe disposal of CCRs, commonly known as coal ash, from coal-fired power plants";[201] and
- the **Steam Electric Power Generating Effluent Guidelines** ("ELG") **and Standards**: the EPA first promulgated the regulations in 1974, and later amended them in 1977, 1978, 1980, 1982, and most recently in 2015.[202] "The regulations cover wastewater discharges from power plants operating as utilities."[203]

The costs associated with complying with these Federal regulations have and will continue to place upward pressure on electricity prices, as they are passed onto ratepayers through mechanisms such as the Environmental Cost Recovery tracker.[204] Figure 93 estimates total expenditures associated with environmental compliance projects implemented by each of Indiana's five IOUs over the 2010 to 2020 timeframe. According to the IURC, these costs have totaled more than $4.6 billion over the period, including projects such as the installation of pollution control equipment, as well as converting and refueling units from coal to natural gas. On average, these expenditures represent 24.6% of each utility's rate base, as reported in their most recent base rate cases.

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[199] US EPA. *Basic Information about Mercury and Air Toxics Standards.*

[200] US EPA. *Affordable Clean Energy Rule.*

[201] US EPA. *Disposal of Coal Combustion Residuals from Electric Utilities Rulemakings.*

[202] US EPA. *Steam Electric Power Generating Effluent Guidelines.*

[203] Ibid.

[204] Indiana Utility Regulatory Commission. *Indiana Utility Guide.* 2019 Edition.

Figure 93. Environmental compliance expenditures by utility in Indiana, 2010-2020

Utility	Estimated environmental compliance expenditures	% of utility's rate base
Duke	$889,000,000	8.7%
I&M	$779,798,000	15.8%
IPL	$1,586,000,000	47.1%
NIPSCO	$1,045,000,000	25.4%
Vectren	$340,000,000	26.1%
	$4,639,798,000	**24.6%**

Sources: IURC. *2019 Annual Report.* 2019; third party commercial database.

8.1.4 Contribution of trackers to historical rate increases

As discussed in Section 7, electricity prices in Indiana across all customer classes have increased at a CAGR of 2.9% over the 2010-2019 period. In the preceding subsections, and as corroborated by the IURC, we determined that rates have primarily increased as a result of changes in customers and their use of utility service, the emergence of a need to replace aging infrastructure, as well as substantial costs incurred to comply with Federal environmental regulations.[205]

To assess these three factors' contribution to historical electricity price increases, we have analyzed the historical trend in trackers used by the State's IOUs to recover associated costs from ratepayers. Observing changes in the level of trackers provides a high-level, illustrative view of the relative contribution of the three cost drivers as they are partially reflected in the following trackers:

> **Trackers:** adjustable rate mechanisms for specific expenses and capital investments. Tracking mechanisms provide timely flow-through of specifically defined costs to retail rates, compared to adjustments that would occur as a result of a rate case.
>
> Source: IURC. *Indiana Utility Guide.* 2019 Edition.

- the **Demand Side Management** tracker, which is used by IOUs to recover costs for energy efficiency programs (which includes program costs, as well as lost revenues).[206] In 2019, this tracker accounted for on average 27% of total trackers on residential electricity bills across all IOUs;
- the **TDSIC** tracker, which, as discussed in Section 8.1.2, allows utilities to recover costs for projects included in their Commission-approved infrastructure plans. In 2019, only Duke, NIPSCO, and Vectren used this tracker, which accounted for 9% of total trackers on residential electricity bills for customers of these three utilities; and
- the **Environmental Cost Recovery** tracker, which is used by IOUs to recover costs associated with installing, operating, and maintaining emissions control equipment. In

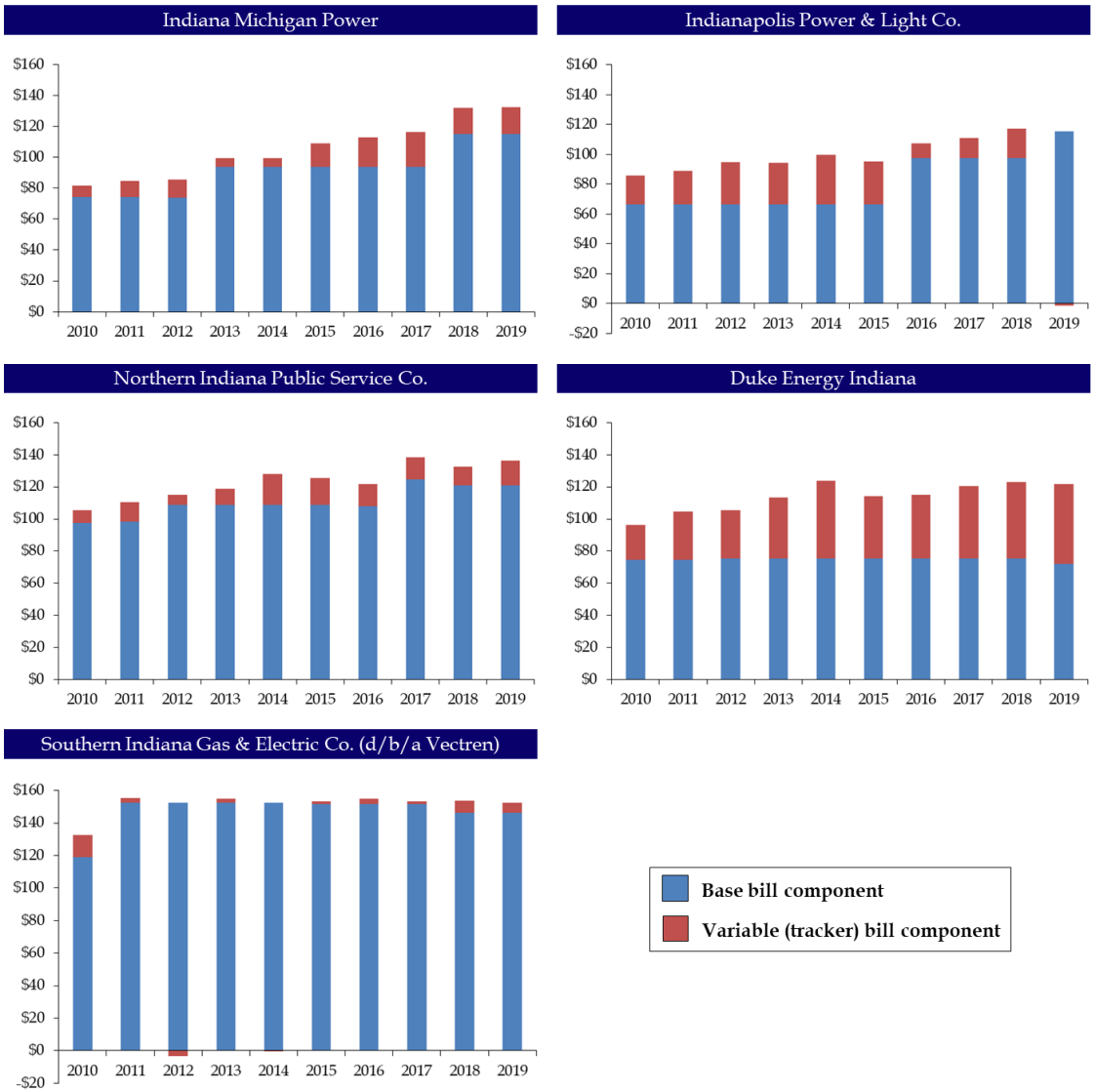
[205] Ibid.

[206] Indiana General Assembly. *IC 8-1-8.5-9.*

2019, all IOUs used this tracker except Vectren, accounting for 13% of total trackers on residential electricity bills for customers of the four IOUs (I&M, IPL, NIPSCO, and Duke).

The contribution of all statutorily allowed trackers to total electricity bills is sizeable. Figure 94 records the average electricity bill over the 2010-2019 period for residential customers in Indiana with a monthly consumption level of 1,000 kWh, as reported in the IURC's annual Residential Bill Survey. The data is shown by utility and is further broken down by the base electricity bill (blue), and the variable component of the electricity bill (red) – whereby the latter reflects the total level of trackers.

Figure 94. Base and tracker bill components for IOUs in Indiana, 2010-2019 (average electricity bill for 1,000 kWh usage residential customer, July 1 billing)



Note: IPL implemented new base rates in 2019.

Source: IURC. *Electricity Residential Bill Survey*. 2010-2019. <https://www.in.gov/iurc/2761.htm>

Over the 2010-2019 period, trackers contributed an average of 16% to the typical residential electricity bill. This proportion was highest for Duke and IPL over the period (for which trackers represented 34% and 21% of the typical residential bill, respectively), and lowest for Vectren (for which trackers represented only 2% of the typical residential bill on average). Between 2010 and 2019, total trackers on residential electricity bills have increased by a customer-weighted CAGR of 7.9% across all IOUs, except IPL.[207] Growth in total trackers was highest for I&M and Duke, which had CAGRs of 10.4% and 9.6%, respectively (2010-2019).

8.2 Continued drivers

In addition to the drivers discussed in Section 8.1, which will continue to impact electricity rates going forward, there are a number of other issues that could impact future rates in Indiana, including: historically low natural gas prices, changing demand from new technologies, the emergence of distributed energy resources ("DERs"), tax credits, and evolving environmental regulations. The following subsections explore each of these issues in turn, focusing particularly on the factors identified by the ICCF in its initial RFP.

8.2.1 Fuel sources

As discussed in Section 5.2.1, Indiana's generation mix has evolved over the past decade, with coal generation declining at a CAGR of -6.6% over the 2010-2019 period, and natural gas-fired generation rising at a CAGR of 19.4% over the same period. As of 2019, coal accounted for 59% of in-state generation, while natural gas accounted for 31%. This changeover can be attributed to a combination of factors, including numerous coal retirements, as well as more stringent environmental rules that are relatively more favorable to gas-fired technologies.

This transition has also coincided with a sharp decrease in natural gas prices, owing to increased shale production and technological advancements in extraction techniques, such as hydraulic fracking and horizontal drilling.[208] Between 2008 and 2019, the cost of natural gas delivered to electric generating plants fell at a CAGR of -9.9%, from a high of $58.1/MWh in 2008 to historical lows of $18.5/MWh by 2019. This has brought natural gas costs generally in line with coal costs, which have remained relatively flat, averaging $19.1/MWh over the 2008-2019 period.[209]

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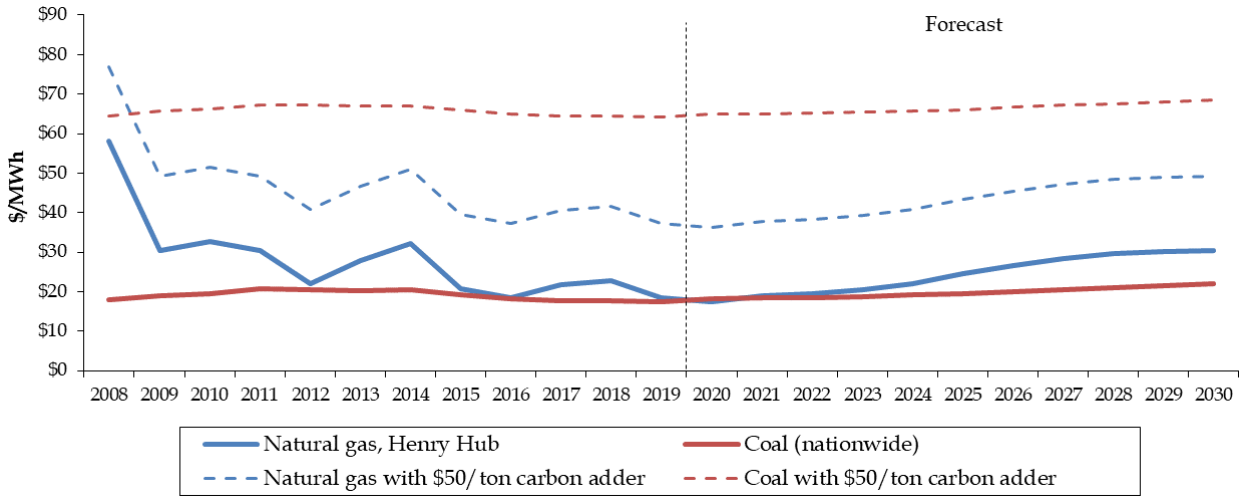
[207] Note: IPL implemented new base rates in 2019, and as such, total trackers appearing on a typical residential electricity bill declined from a charge of around $19.25/month in 2010 to a credit of $1.31/month by 2019.

[208] US EIA. *Natural Gas Explained.* <https://www.eia.gov/energyexplained/natural-gas/where-our-natural-gas-comes-from.php>

[209] The costs of fuel delivered to electric generating plants are reported by the US EIA in $/MMBtu. To convert these costs to $/MWh, we multiplied the $/MMBtu values by the assumed heat rates for coal and natural gas-fired power plants, and divided the totals by 1,000. LEI used the assumptions in the EIA's 2020 Annual Energy Outlook, where ultra-supercritical coal plants are assumed to operate at a heat rate of 8,638 Btu/kWh, while combined-cycle, single shaft natural gas plants are assumed to operate at a heat rate of 6,431 Btu/kWh.

Figure 95 illustrates these trends in the costs of natural gas and coal delivered to electric generating plants, and also includes the US EIA's forecast for costs out to 2030.[210] In addition, LEI has calculated these costs with a $50/ton carbon adder[211] (see dotted lines), which causes coal to become far less economic than natural gas on a $/MWh basis. This is due to the following factors: coal has a higher carbon content than natural gas (216 lb/MMBtu versus 117 lb/MMBtu);[212] and coal plants tend to have a higher heat rate than natural gas-fired power plants (8,638 Btu/kWh versus 6,431 Btu/kWh).[213]

Figure 95. Costs of fuel delivered to electric generating plants, 2008-2030 ($/MWh)



Notes: Historical price for coal delivered to electric generating plants represents the national average for the following coal types: anthracite, bituminous, subbituminous, lignite, waste coal, and coal-derived synthesis gas. Forecast coal prices are taken from the EIA's Annual Energy Outlook, which is reported for steam coal only. Costs reported as $/MMBtu by EIA, LEI converted these values to $/MWh assuming a heat rate of 8,638 Btu/kWh for coal and 6,431 Btu/kWh for natural gas. Carbon adder assumes CO_2 content of 216 lb/MMBtu for coal and 117 lb/MMBtu for natural gas.

Source: US EIA. *Short-Term Energy Outlook.* August 11, 2020; US EIA. *Annual Energy Outlook.* January 29, 2020; US EIA. *How much carbon dioxide is produced when different fuels are burned?* June 17, 2020.

Although the increased supply of cheap natural gas has placed downward pressure on electricity prices, the material drop in natural gas prices over the past decade has put pressure on conventional power plants that are not able to take advantage of this cheaper fuel source. This has resulted in coal-fired generation generally becoming more expensive than gas-fired generation on a short-run marginal cost basis. Therefore, the utilization rate of coal plants has dropped, but ratepayers are still required to pay for the capital costs of these units, as they are already incorporated into utilities' rate bases. In addition, the costs associated with converting

[210] Due to limited data availability, LEI presents costs of fuel delivered to electric generating plants at a national level rather than for Indiana specifically.

[211] $50 per ton was chosen consistent with the embedded cost of carbon emissions in the Section 45Q tax credit.

[212] US EIA. *How much carbon dioxide is produced when different fuels are burned?* June 17, 2020.

[213] US EIA. *Assumptions to the Annual Energy Outlook 2020: Electricity Market Module.* January 2020.

coal plants to natural gas and decommissioning old coal plants are also passed onto ratepayers, which puts further upward pressure on electricity prices.

Going forward, as projected in the EIA's 2020 Annual Energy Outlook (Reference Case), the cost of natural gas delivered to electric generating plants is expected to increase from an historically low base at a CAGR of 5.7% (2020-2030), reaching $4.71/MMBtu by 2030 (or $30.3/MWh, assuming a heat rate of 6,431 Btu/kWh).[214] The persisting low natural gas prices should continue to make natural gas-fired generation a competitive source of new generation capacity going forward.

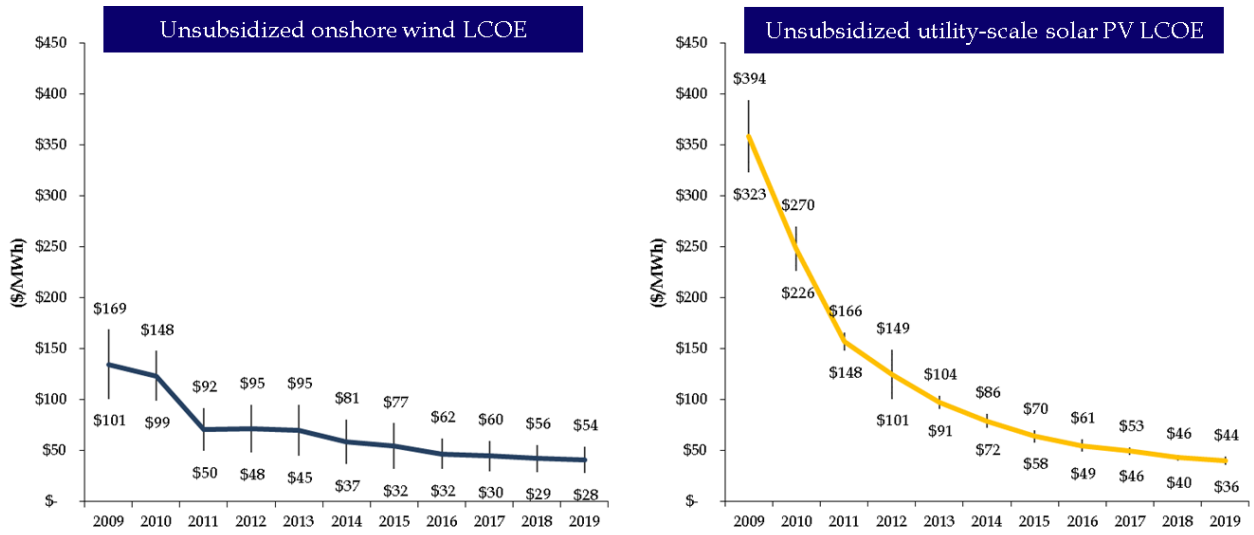
8.2.2 Technology

The capital costs of utility-scale renewables have also been declining over the past decade to bring them generally in line with the economics of fossil fuel-fired power. Figure 96 illustrates the trend of declining costs of wind and solar, for which their levelized costs of electricity ("LCOEs") have decreased at a CAGR of -11.2% and -19.7%, respectively, over the 2009-2019 period. The increased supply of cheaper renewables, made possible primarily through technological developments, places downward pressure on electricity prices.

Levelized cost of electricity represents the average revenue per unit of electricity generated that would be required to recover the costs of building and operating a generating plant over an assumed financial life.

Source: EIA

Figure 96. Historical wind and solar LCOEs



Notes: Onshore wind LCOEs calculated based on the assumed capacity factor of between 38-55%. The assumed capacity factor for utility-scale solar PV (crystalline) is between 21-32%. Section 4.5.1 and 4.5.2 discuss the technical potential of wind and solar, respectively, in Indiana.

Source: Lazard. *Levelized Cost of Energy Analysis – Version 13.0.* November 2019.

[214] US EIA. *Annual Energy Outlook.* January 29, 2020.

As a result of the decreasing costs of renewables, as well as a culmination of other factors, including low natural gas prices and tightening environmental regulations, utilities in Indiana are beginning to transition to a cleaner power supply. As observed by the IURC, "[w]hile the speed of change depends on the specific circumstances of a given company, the evolution is clear: greater diversification of generation portfolios, including greater incorporation of renewables and gas-fired generation facilities, and reduced reliance on coal-fired generation."[215]

This sentiment has been confirmed by recent IRPs filed by Indiana's regulated utilities, which indicate a utility's long-term resource plans. Therein, utilities anticipate retiring approximately 7,730 MW of coal plants by 2028 (as illustrated in Figure 40, Section 5.2.1). In contrast, by 2030, utilities anticipate adding 4,840 MW of solar, 3,319 MW of natural-gas fired generation, and 1,557 MW of wind (as demonstrated in Figure 41, Section 5.2.1) – according to the preferred portfolios outlined in each utility's most recent IRP. This heightened reliance on cheaper sources of power (namely natural gas and renewables), while maintaining resource diversity, helps moderate electricity prices in the future provided the costs of legacy assets do not offset any declines. However, given the intermittent nature of renewables, it is important to caveat that an increased role for these resources will necessitate investments to firm up power, which need to be taken into account.

8.2.3 Demand

Predicting future system demand has become increasingly challenging due to the opposing forces of many influences. On the one hand, will demand fall due to increasing amounts of energy efficiency programs and the expansion of customer-owned supply (in the form of DERs such as behind-the-meter solar or energy storage solutions)? Or, on the other hand, will demand increase due to the electrification of activities such as transportation and heating, whereby customers need to plug in more devices (i.e., electric vehicles ("EVs") and electric space heating devices)?

> *"[L]oad growth has slowed markedly over the last decade and is generally projected to increase slowly or decrease slowly depending on the circumstances of the specific utility forecast. This is the case for Indiana utilities and across the [MISO and PJM] multi-state regions."*
>
> - IURC. *2020 Report to the 21st Century Energy Policy Development Task Force.* August 14, 2020. p. viii.

The outlooks for each of these factors in Indiana are as follows:

- **energy efficiency:** the State Utility Forecasting Group[216] for the IURC projects that incremental energy efficiency programs (defined as new programs plus the expansion of existing programs) could reduce peak demand by a further 800 MW by 2037, despite the

[215] Indiana Utility Regulatory Commission. *2020 Report to the 21st Century Energy Policy Development Task Force.* August 14, 2020. p. 6.

[216] "SUFG was formed in 1985 when the Indiana legislature mandated a group be formed to develop and keep current a methodology for forecasting the probable future growth of electricity usage within Indiana. The Indiana Utility Regulatory Commission contracted with Purdue and Indiana Universities to accomplish this goal." (Source: SUFG. *Indiana Electricity Projections: The 2019 Forecast.* November 2019. p. viii.)

rolling back of the State's energy efficiency standard in 2014.[217] This represents an expansion in energy efficiency programs by a CAGR of approximately 8.2% (2018-2037). In contrast, demand response loads are projected to remain flat at around 1,600 MW throughout the forecast horizon out to 2037;[218]

- **DERs:** the Lawrence Berkeley National Laboratory ("LBNL") for the IURC projected potential deployment levels of DERs (including rooftop solar, electric vehicle charging, and battery storage) among residential and commercial customers in Indiana across six scenarios. The base scenario (or business as usual case) anticipates that by 2040, Indiana could reach 356 MW of rooftop solar capacity (i.e., a penetration rate of 0.5% of residential and commercial customers), 1,705 MW of EV charging capacity (i.e., an adoption rate of 10% of residential customers), and 1 MW of installed behind the meter storage capacity;[219] and
- **electrification:** according to a whitepaper recently published by MISO, footprint-wide energy could be expected to increase between 30 and 50% by 2040 as a result of increased electrification (Future II and Future III scenarios, respectively).[220] This represents "a wide but plausible range of electrification" that is supported by other studies of the electricity sector.[221] However, there are currently no state-level incentives in Indiana for electric vehicles,[222] so it is unclear if this electrification level is plausible for the State.

Energy efficiency programs are aimed at reducing the energy used by specific end-use devices and systems, typically without affecting the services provided.

Demand response programs are incentive-based programs that encourage electric power customers to temporarily reduce their demand for power at certain times in exchange for a reduction in their electricity bills.

Distributed energy resources are small, modular, energy generation and storage technologies that provide electric capacity close to the source of load and are either connected to the distribution system or isolated from the grid in standalone applications.

Sources: EIA, NREL

Overall, and as discussed in Section 5.2.3, recent forecasts by the SUFG anticipate electricity usage and peak demand in Indiana could grow modestly at 0.7% and 0.6% per year, respectively, over the next 20 years.[223] This forecast is higher than recent historical electricity usage and peak

[217] State Utility Forecasting Group for the Indiana Utility Regulatory Commission. *Indiana Electricity Projections: The 2019 Forecast.* November 2019.

[218] Ibid. LEI believes that demand response loads are more likely to increase rather than remain flat.

[219] Indiana Utility Regulatory Commission. *2020 Report to the 21st Century Energy Policy Development Task Force.* August 14, 2020.

[220] MISO. *MISO Futures Whitepaper: MTEP 21.* April 27, 2020.

[221] Ibid.

[222] Plug In Midwest. *Midwest Incentives.* <http://www.pluginmidwest.org/midwestincentives/>

[223] State Utility Forecasting Group for the Indiana Utility Regulatory Commission. *Indiana Electricity Projections: The 2019 Forecast.* November 2019.

demand, which grew at CAGRs of 0.5% and 0.2%, respectively, over the 2009-2018 period. Notably, these forecasts do not factor in the impacts of the ongoing COVID-19 pandemic, which could lead to a sustained reduction in electricity demand in the short- and mid-term. Section 9.7 covers the impacts of COVID-19 on the electricity sector in more detail. Generally, and as explained in Section 8.1.1, flattening or declining electricity system usage will place upward pressure on electricity prices, as the fixed costs of providing electric service will have to be spread across a shrinking customer base.

8.2.4 Tax credits

Investments in renewable and carbon capture resources are driven by a multitude of factors, including economics, environmental regulations, and technological innovation. Tax credits provide financial incentives to improve the economics of certain projects, and hence incents the increased build-out of qualifying resources. Currently, the following Federal tax credits are available for renewable and carbon capture development:

> **Carbon capture**, utilization and storage ("CCUS") is a process that captures carbon dioxide emissions from sources like coal-fired power plants and either reuses or stores it so it will not enter the atmosphere.
>
> Sources: US DOE.

- the **Business Energy Investment Tax Credit ("ITC"):** the ITC is a Federal tax credit which can be claimed on a percentage of the cost of installation for qualifying renewable energy technologies, including solar, fuel cells, small wind turbines, geothermal, microturbines, and CHP systems. The ITC was enacted in 2006 with a 30% credit, but will slowly be phased down starting in 2020. For example, solar systems which begin construction in 2020 will qualify for a 26% ITC, which will further decrease to 22% in 2021, and 10% thereafter;[224]
- the **Renewable Electricity Production Tax Credit ("PTC"):** the PTC is a per-kilowatt-hour tax incentive applied to the first ten years of a project's operation, adjusted for inflation. The first PTC was enacted in 1992 and has been extended 12 times, most recently extending the expiration date for wind resources commencing construction before December 31, 2020. The PTC for these resources will be applied at a rate of $0.0184/kWh;[225] and
- the **Section 45Q Tax Credit** for carbon capture projects: Section 45Q of the Internal Revenue Code provides a tax credit on a per-ton basis for CO_2 that is captured and either: (1) utilized for enhanced oil/natural gas recovery or in direct air capture projects ($20.22/metric ton in 2020, rising to $35/metric ton by 2026); or (2) stored in a secure geologic formation ($31.77/metric ton in 2020, rising to $50/metric ton by 2026).[226] The

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[224] DSIRE. *Business Energy Investment Tax Credit (ITC).* Last updated February 13, 2020. <https://programs.dsireusa.org/system/program/detail/658>

[225] DSIRE. *Renewable Energy Production Tax Credit (PTC).* Last updated July 14, 2020. <https://programs.dsireusa.org/system/program/detail/734>

[226] Lexology. *IRS Releases Section 45Q Proposed Regulations for Carbon Capture Projects.* June 5, 2020.

tax credit is available for a 12-year period, beginning when the carbon capture equipment is placed in service at a qualified facility.[227]

A combination of falling renewables prices and favorable renewable resource potential suggests that no additional state-mandated incentives are needed to drive an increased penetration of renewables. Federal tax credits serve to reduce costs for renewables consumption, even if they reduce Federal tax revenues. Despite the gradual sunset of Federal incentive programs such as the PTC, it is expected that the drivers for renewable energy will sustain their continued build-out in Indiana. This is corroborated by the preferred resource portfolios of IOUs in the State, as discussed in Section 8.2.2, which include the increased adoption of solar and wind resources going forward.

8.2.5 Environmental regulations

As discussed in Section 8.1.3, tightening environmental regulations over the past decade have led to almost $4.5 billion in compliance costs incurred mainly at coal plants in Indiana. These capital expenditures have not only placed upward pressure on electricity prices, but have also placed increased pressure on the profitability of these coal plants.

Going forward, costs associated with these plants could increase further in light of recently introduced legislation. In March 2020,[228] HB 1414 was passed in the State, requiring that prior to proceeding with a coal retirement, utilities must first provide written notice to the IURC, and the IURC must then conduct a public hearing to determine the reasonableness of the planned retirement.[229] This rule is anticipated to sunset in May 2021, before any coal plants are scheduled to retire. If policies such as HB 1414 continue in Indiana, and are successful in slowing the pace of coal retirements and imposing further costs to keep these units in commercial operation, one would expect electricity prices to continue their upward trend. For example, the SUFG for the IURC projected that electricity prices could rise between 1-4% over its reference scenario as a result of potential coal moratoriums as far out as 2025 or 2030.[230] Of course, requiring a hearing does not necessarily mean a coal plant shutdown will be cancelled; the hearing may show the shutdown to be reasonable based on the information received by the Commission.

8.3 Summary of historical and continued cost drivers

As discussed throughout Sections 8.1 and 8.2, electricity prices in Indiana will continue to be driven by a multitude of factors. As summarized in Figure 97, flattening or declining electricity demand, aging infrastructure requiring costly maintenance or upgrades, as well as environmental retrofits to comply with tightening regulations could lead to electricity price

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[227] US DOE, Office of Fossil Energy. *Internal Revenue Code Tax Fact Sheet.* October 2019.

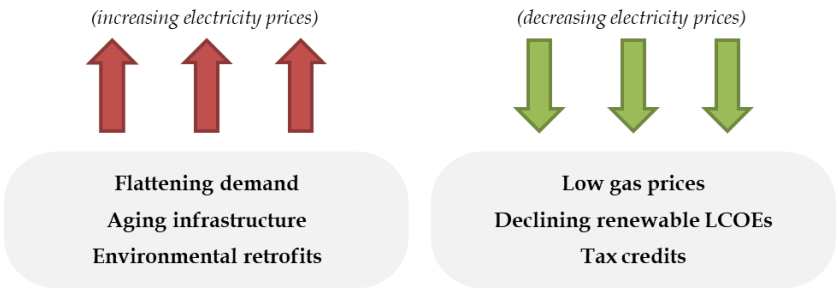
[228] Utility Dive. *Indiana passes coal plant support bill as Democrats removed from conference committee deliberations.* March 11, 2020.

[229] Indiana General Assembly. *House Enrolled Act No. 1414.* 2020.

[230] Indiana Utility Regulatory Commission. *2020 Report to the 21st Century Energy Policy Development Task Force.* August 14, 2020.

increases. In contrast, low gas prices, declining renewables LCOEs, and continued tax credits to support renewable and carbon capture projects should lead to declining electricity prices.

Figure 97. Directional electricity price impact of various cost drivers



8.4 Cost drivers in neighboring states

As demonstrated in Section 7.1 (Figure 76), Indiana ranked fourth in the region in terms of average electricity prices in 2019 (9.9 cents/kWh), cheaper only than Michigan (11.6 cents/kWh). This is in contrast to the State's position in 2010, at which point Indiana ranked second in the region (7.7 cents/kWh), behind only Kentucky (6.7 cents/kWh). As a result of this change in relative ranking over the 2010-2019 period, Indiana has experienced the highest growth rate in average electricity prices in the region, rising at a CAGR of 2.9% across all customer classes.

As discussed throughout this chapter, the deterioration in Indiana's relative electricity price advantage has largely been due to flattening demand, as well as investments in environmental retrofits and in transmission and distribution projects to upgrade aging infrastructure. Notably, Indiana's load declined over the 2010-2019 period (CAGR of -0.4%), which is equal to the regional average,[231] but below the national average of 0.2%.

These cost drivers, as well as the continued cost drivers discussed previously (historically low natural gas prices, declining capital costs of renewables, Federal tax credits incentivizing renewables and carbon capture, and tightening environmental regulations), have impacted all states in the region to some degree – for example:

- **economic pressure on coal plants from Federal regulations:** states with a greater reliance on coal for electricity generation – namely Kentucky (72% in 2019) and Ohio (39% in 2019) – have faced rising prices. Figure 98 shows the percentage of coal generation for the region as compared to the national average, using data from the US EIA as of 2019. From 2010 to 2019, Kentucky faced the second highest growth rates in electricity prices across the region (CAGR of 2.8%), behind Indiana (CAGR of 2.9%). On a national level, of the top ten states in the US relying on coal for electricity generation as of 2019, eight dropped

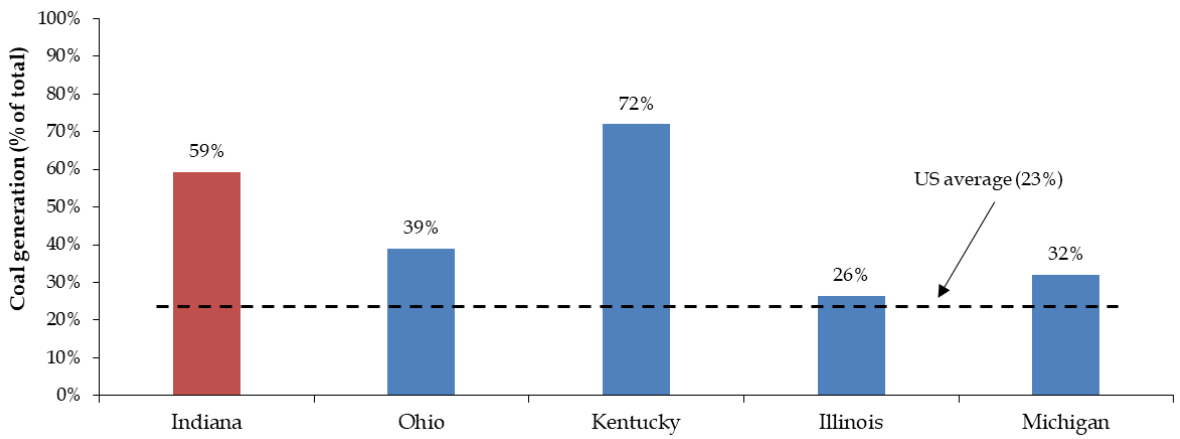
[231] We have excluded Kentucky from the regional average as it has experienced an anomalous contraction in load over the 2010-2019 period of -2.4%. Including Kentucky brings the regional average down to -0.8% for the period.

in their national ranking for total average electricity prices over the 2010-2019 period.;[232] and

- **low natural gas prices:** states with greater natural gas-fired capacity have been able to take advantage of declining natural gas prices – such as Ohio (43% of electricity generation from natural gas in 2019). This has enabled Ohio to somewhat counteract the upward pressure on coal prices with the downward pressure on prices from natural gas, holding growth rates in electricity prices over the 2010-2019 period to a CAGR of 0.5% (below the regional average CAGR of 1.6%).

The following subsections highlight a selection of additional cost drivers that are unique to each of Indiana's neighboring states, which could place upward pressure on their electricity rates going forward.

Figure 98. Coal generation as proportion of total mix in Indiana and neighboring states versus US average (2019)



Source: US EIA data <https://www.eia.gov/electricity/data/state/>

8.4.1 Ohio

As of 2019, Ohio has a significant amount of coal (39%) and nuclear (14%) in its generation mix. In 2019, the State's legislature passed *House Bill 6*, which includes over $1 billion in financial assistance to keep some of Ohio's nuclear and coal-fired power plants operating.[233] This legislation is described in further detail below, but will impact future electricity rates as the law sets forth surcharges to customer bills until 2030.

[232] US EIA. *Form 861 data.*

[233] US EIA. *Ohio State Energy Profile.* June 18, 2020. <https://www.eia.gov/state/analysis.php?sid=OH>

Ohio legislation providing financial support for coal and nuclear plants

In July 2019, Ohio lawmakers approved House Bill 6, authorizing $150 million in annual nuclear subsidies, $50 million in annual coal subsidies, and $20 million in annual subsidies for selected rural solar projects. The Bill also reduced the state's RPS (from 12.5% to 8.5% by 2026) and set forth a plan to eliminate its energy efficiency resource standard ("EERS") over the next seven years. To finance the costs of the subsidies, the state will redirect ratepayer dollars that were previously supporting the RPS and EERS programs (which have amounted to on average $4.74 per month for residential customers). Essentially, from 2021 through 2027, customers will be subject to a new monthly surcharge ranging from 85 cents (residential customers) to $2,400 (large industrial customers) to fund a "nuclear generation fund." In addition, until 2030, customers are subject to a nonbypassable monthly rider ranging from $1.50 (residential customers) to $1,500 (commercial and industrial customers) to subsidize two coal plants.

Proponents of the Bill have suggested that as a result of the redirect in funding, residential customers could see bills reduced by approximately $3.78/month by 2027. However, it is unclear what additional costs customers will face in the long-term as a result of stripped back funding for energy efficiency programs in favor of supporting uneconomic generation assets. Some opponents suggest that the Bill could lead to a $7.01/month increase to the average residential customer's electricity bill, due to lost savings as a result of reduced energy efficiency efforts.

The Bill has been criticized as a bailout that would negatively impact Ohio's growing natural gas industry.

Sources: National Conference of State Legislatures. *2019 Legislative Energy Trends.* February 2020; Pelzer, Jeremy. *Nuclear Bailout Bill Passes Ohio Legislature, Signed by Gov. Mike DeWine.* July 23, 2019; S&P Global. *Ohio Nuclear Legislation Under Fire as FirstEnergy Reiterates Innocence*. July 28, 2020. Energy News Network. *HB 6 costs go well beyond claimed harm to public trust in Ohio.* September 3, 2020.

8.4.2 Kentucky

Kentucky relies on coal for power generation more than any other state in the region – in 2019, coal-fired power plants supplied 72% of the State's electricity generation (see Figure 98). This is due in large part to Kentucky's heavy presence in coal mining and production, with 20% of all operating coal mines in the country located in the state, behind only West Virginia and Pennsylvania.[234]

Although Kentucky has consistently enjoyed the lowest electricity prices in the region for the timeframe studied (2010-2019 – see Figure 76, Section 7.1), which has helped to attract manufacturing to the state,[235] it has also experienced the second fastest growth rates of all states in the region. From 2010 to 2019, electricity prices across all customer classes in Kentucky increased at a CAGR of 2.8%, compared to the regional average CAGR of 1.6% for the same period. Should Kentucky continue to rely on coal for power generation, this trend of rising

[234] US EIA. *Kentucky State Energy Profile.* June 18, 2020. <https://www.eia.gov/state/analysis.php?sid=KY>

[235] Ibid.

electricity prices may be sustained, as low natural gas prices and tightening environmental regulations maintain pressure on the economics of operating and maintaining coal-fired power plants.

8.4.3 Illinois

Illinois utilizes nuclear power for more than half of its electricity generation – in 2019, nuclear accounted for 54% of the State's electricity generation mix. Illinois houses the most nuclear power plants in the US, and as such, generates more electricity from nuclear energy than any other state in the country.[236]

In 2016, when faced with the potential closures of two of the State's six nuclear power plants (Clinton and Quad Cities), which were scheduled to close in 2017 and 2018 due to economic pressure, the Illinois state legislature passed the *Future Energy Jobs Act*.[237] The Act, among other policies, established the nation's first legislatively mandated nuclear subsidies (see the textbox below for further details). These subsidies, which are available annually until 2027, are being funded by ratepayers through monthly surcharges.[238]

Potentially adding to this upward pressure on electricity prices is the energy legislation being considered by the Illinois General Assembly. As of writing, state legislators are considering the *Clean Energy Jobs Act* (House Bill 3624), which calls for reaching 100% renewable energy in the state by 2050.[239] Although the capital costs of renewables are declining (as discussed in Section 8.2.2), the costs incurred to firm up power from these intermittent generation resources could inevitably place upward pressure on prices going forward. Therefore, both policy actions (i.e., generation subsidies for nuclear and the potential legislation calling for 100% renewables) are likely to place upward pressure on electricity rates in Illinois going forward, as the state diverges from a least-cost, technology neutral approach to energy policy. However, it should be noted that the *Clean Energy Jobs Act* caps rate increases through mid-2023 to 2.67% of the amount paid per kWh by customers during the year ending May 31, 2009, increasing the cap to 4.88% beginning mid-2023.[240]

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[236] US EIA. *Illinois State Energy Profile.* May 21, 2020. <https://www.eia.gov/state/analysis.php?sid=IL>

[237] Ibid.

[238] National Governors Association. *Policy Update: State Policy Support for Nuclear Generation.* April 25, 2019.

[239] Illinois General Assembly. *HB 3624.*

[240] Ibid.

Illinois legislatively mandated nuclear subsidies

Similar to the case of Ohio, generation subsidies for nuclear facilities threatening closure due to economic hardship have also been promulgated in Illinois. Through the *Future Energy Jobs Act* (2016), Illinois enacted the first legislatively mandated nuclear subsidies in the US. Under the Act, the legislature established a Zero Emission Standard program, designed to preserve existing and promote the build-out of new zero-emission generation resources.

Under the program, utilities in the state are required to purchase zero emission credits annually from qualifying resources, which include two of the state's six nuclear plants – Quad Cities and Clinton. This amounts to approximately $235 million in annual credits for the energy produced by these two plants for a contract length of ten years. As was the case in Ohio, the Illinois legislation drew criticism from observers, with some arguing that it is essentially a corporate bailout. In terms of bill impact, the FEJA established caps to rate increases until 2030 for each customer class: for residential customers, bill increases are limited to between $0.25-$0.35 per month; for commercial and small to medium industrial customers, average bill increases are capped at 0.12 cents/kWh; and for large industrial customers (> 10 MW), bill increases are limited to 0.078 cents/kWh.

Sources: ICC presentation to NARUC. *Overview of Illinois Public Act 99-0906*; Utility Dive. *Illinois Energy Law Revives Renewables while Aiding Nuclear.* April 30, 2018; Power Grid International. *Illinois Passes Subsidy Bill to Save State's Nuclear Power Plants.* December 2, 2016.

8.4.4 Michigan

Michigan has consistently experienced the highest electricity prices in the region, over the entire time period studied. From 2010 to 2019, average electricity prices in Michigan rose from 9.9 cents/kWh in 2010 to 11.6 cents/kWh by 2019 – compared to the regional average of 8.5 cents/kWh and 9.8 cents/kWh, respectively (see Figure 76, Section 7.1).

Michigan could continue to experience relatively high electricity prices as a result of the recently signed Executive Order 2020-10, which sets out the goal of statewide decarbonization by 2050.[241] An aggressive target such as this – which has to date only been implemented in eight[242] other states across the country – introduces substantial uncertainty as to the future trajectory of electricity rates in the state.

8.5 Illustrative forecast for future rates

To provide an indication of future rates, LEI forecast the blended electricity rates of IOUs in Indiana. As discussed in Section 5.2.4, IOUs cover 79% of retail sales and serve various parts of

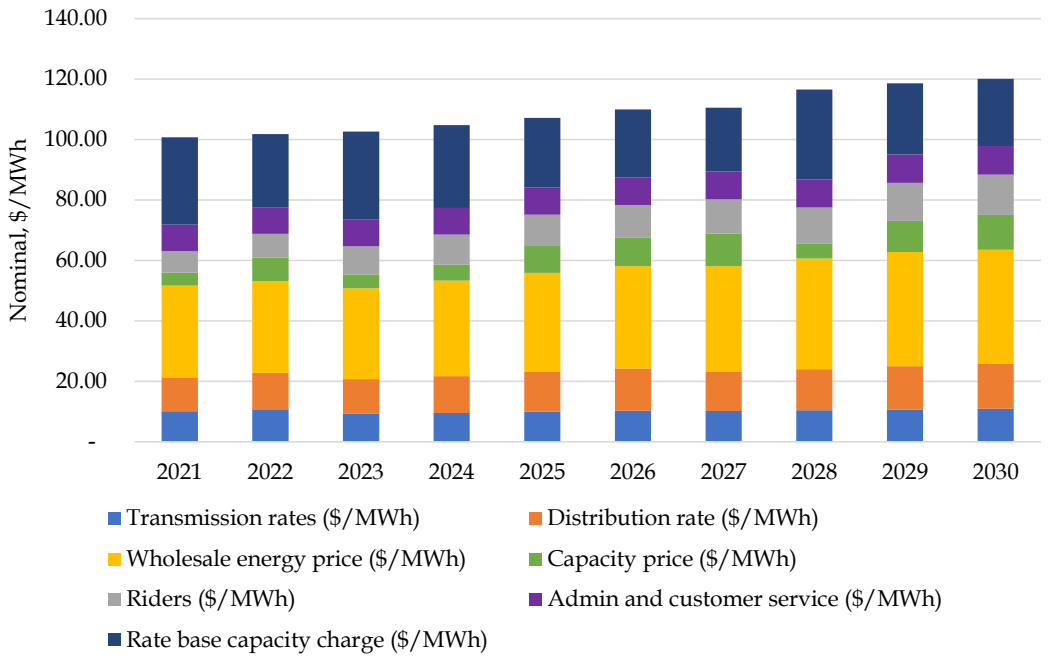
[241] The Office of Governor Gretchen Whitmer. *Governor Whitmer Announces Bold Action to Protect Public Health and Create Clean Energy Jobs by Making Michigan Carbon-Neutral by 2050.* September 23, 2020.

[242] Daily Energy Insider. *Michigan Gov. Whitmer signs executive order to create carbon neutral state by 2050.* September 25, 2020.

Indiana. Therefore, their projected energy prices are reasonably representative of the future energy outlook of the State. In addition, financial data is not readily available for most of the munis and all the REMCs, which makes forecasting of the energy prices for these utilities more difficult. Nevertheless, LEI compared the overall rates among the different electricity providers and noted that the difference in electricity rates between munis and IOUs was only 1.5% per year historically (2012-2018). As for REMCs, LEI anticipates that their electricity rates would continue to be higher than the forecast blended electricity rates for IOUs discussed in this section.

Subject to the associated assumptions, LEI forecasts that the blended (combining generation, transmission, distribution, and various riders) IOU electricity rates in Indiana over the next ten years will increase at a CAGR of 2.0%, lower than the average growth rate of 2.9% from 2010-2019. The blended electricity rate forecasts, which are shown on Figure 99, align with the historical electricity rates of the IOUs and take into account the "most likely" set of assumptions. Actual outcomes may differ substantially, however. The different components of the projected electricity rates are discussed in the subsequent sections.

Figure 99. Indicative forecast delivered blended energy rates in Indiana



Source: LEI analysis

Wholesale energy prices (generation) would contribute most to the rates at an average of 31% per year, followed by the rate base capacity charge (23%), distribution rates (12%), various riders (10%), transmission rates (9%), admin and customer service charges (8%), and capacity/resource adequacy costs (7%).

There are various drivers for the growth in wholesale electricity rates. For the wholesale energy prices in MISO and PJM, the drivers include fuel prices, supply-demand dynamics (new entry and retirements and load forecasts), renewable development and integration, and evolving

market rules. LEI recognizes that Indiana is vertically integrated; thus, while generation energy costs are based on projected ISO wholesale market prices, residual unrecovered ratebase generation costs are captured by the rate base capacity charge. For transmission, the factors that impact rates include the level of rate base growth, the TDSIC planning period, allocation of MISO/PJM regional transmission project costs, and age of the existing assets. Similarly, the drivers of the distribution rate increase include the age of existing assets, TDSIC planning period, and type of utility a customer is facing. The following subsections provide a detailed discussion of each electricity sector forecast.

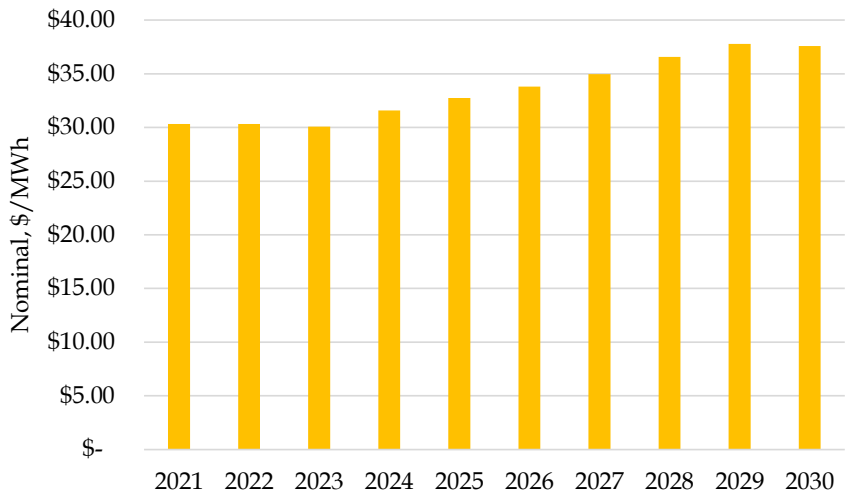
8.5.1 Wholesale energy price forecasts

As mentioned in Section 5.2, Duke Energy, NIPSCO, IPL, Vectren, AEP, Hoosier Energy, IMPA, and WVPA are members of MISO while AEP (including its Indiana subsidiary, I&M), IMPA, and WVPA are members of PJM. The utilities serving Indiana in MISO and PJM are located in MISO Central and the AEP zone of PJM, respectively. In this section, LEI will briefly discuss the projected wholesale energy prices and key drivers in both these ISOs. LEI modeling assumes that when Indiana utility marginal costs for owned generation are below projected ISO costs, ratepayers receive the benefit, and when they are higher, that the utility buys from ISO wholesale markets.

LEI forecasts the energy prices using its proprietary model, POOLMod. Appendix B (page 226) provides more information on how POOLMod works and the assumptions used. LEI's forecast represents a market-oriented reference case, built upon the "most likely" set of assumptions, where generators are assumed to make "just-in-time" capacity investment decisions that are timed to load growth, as we are targeting an effective reserve margin on top of peak load. In other words, new entry is synchronized with reliability reserve requirements set by MISO (as well as RPS set by state regulators where applicable). Note that LEI models the markets under long-term weather-normal and condition-normal assumptions. The ongoing COVID-19 pandemic represents a highly abnormal situation that has extreme short-term and the potential for medium to longer term implications for all markets, including MISO and PJM.

In the next ten years (2021-2030), the average blended wholesale energy prices in Indiana are estimated to range between $30.1/MWh and $37.8/MWh with a CAGR of approximately 2.4% over the ten-year period. The average blended energy prices, which are calculated based on the forecast PJM and MISO energy prices adjusted based on the ISO's load share in the state, are projected to grow during the forecast horizon due to several factors. First, gas prices are assumed to increase by an average of 4.6% per annum in Chicago Citygate Hub and MichCon Citygate Hub between 2021 and 2030. Second, coal retirements due to the tightening of environmental policies and projected poor economics relative to gas are expected over the forecast horizon. Finally, the tightening of the supply and demand growth between 2021 and 2030 will put upward pressure on energy prices.

Figure 100. Projected demand-weighted average blended energy prices in Indiana (nominal $/MWh)



Source: LEI analysis, July-August 2020 Continuous Modeling Initiative ("CMI") round.

8.5.2 Capacity price forecasts

LEI also modeled the capacity prices in MISO and PJM. LEI recognizes that Indiana utilities would likely self-supply capacity; thus, this capacity cost is notional, and used to reduce the rate base capacity charge discussed below. LEI uses its proprietary models for the Regional Capacity Trading Market ("RCTM") and Reliability Pricing Model ("RPM") to simulate capacity transactions in MISO under the Planning Resource Auction ("PRA") construct and the PJM capacity market, respectively. These two capacity models are designed to operate according to MISO's and PJM's existing rules (including each ISO's demand curve), under the assumption that competitive bilateral markets converge to the outcomes that would result from a centralized auction market and the impetus for participation in the recovery of investment costs. We assumed the PRA[243] and the RPM to be a critical platform allowing market participants (load-serving entities and IPPs) to recover their going-forward fixed costs.[244] In other words, market bidders would look to recoup the "missing" portion of their revenue requirement on the capacity market as opposed to passing through their cost to load.[245] Consequently, the decision to build new power plants is based on whether those plants will recover their target levelized cost from the energy and the capacity markets.

Consistent with MISO's and PJM's methodology, LEI simulated supply and demand conditions in its model and integrated transfer limits (imports/exports) at the zonal level to reproduce cost-

[243] The MISO Board of Directors, as well as a number of states, remain opposed to a mandatory capacity construct.

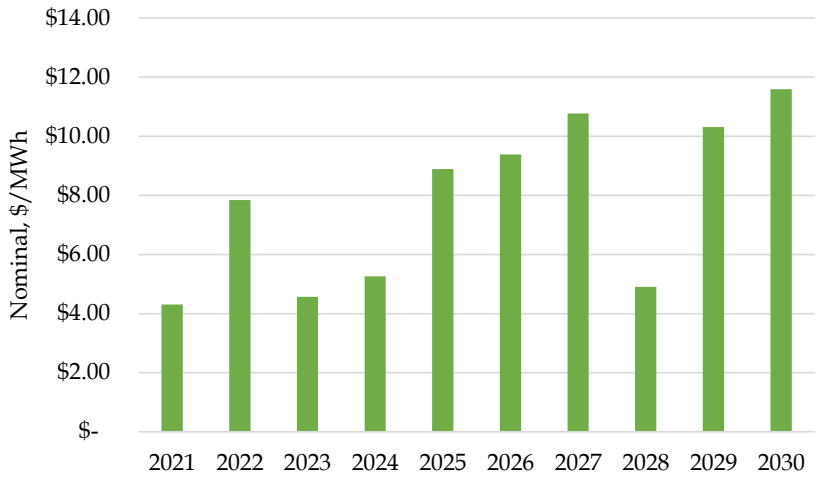
[244] Default Technology-Specific Avoidable Costs published by MISO IMM on January 30th, 2019 were used to represent going-forward fixed costs, where applicable.

[245] MISO's footprint is dominated by vertically integrated utilities which have the ability to recover costs through rate base, diminishing reliance on the PRA.

effective allocation of resources needed to achieve reliability requirements, and resulting price separation.[246] In LEI's model, the decision to add new entry is made at the zonal level based on the number of resources available to comply with reserve margin requirements (more specifically, local reliability requirements).

Based on LEI's analysis, the blended capacity prices will fluctuate over the next ten years due to new generating plants entering the market as needed and clearing the auction as marginal units (to meet different reserve margin targets in different zones). The price volatility is attributable to the different timings of generic new entry, which sets the price in the year it comes online. This observation is consistent with what has happened in past auctions. Also, some plants will likely bid lower in the capacity market during this period as their energy revenues are expected to cover an increasing share of their minimum going forward costs with the projected higher energy prices. The projected blended capacity prices in Indiana range from $4.3/MWh to $11.6/MWh, with an average price of $7.8/MWh during the ten-year period, as shown in Figure 101.

Figure 101. Projected demand-weighted average blended capacity prices in Indiana (nominal $/MWh)



Note: MISO's PRA and PJM's RPM are from June 1 of any one year to May 31 of the following year.

Source: LEI analysis, July-August 2020 Continuous Modeling Initiative ("CMI") round.

8.5.3 Rate base capacity charge

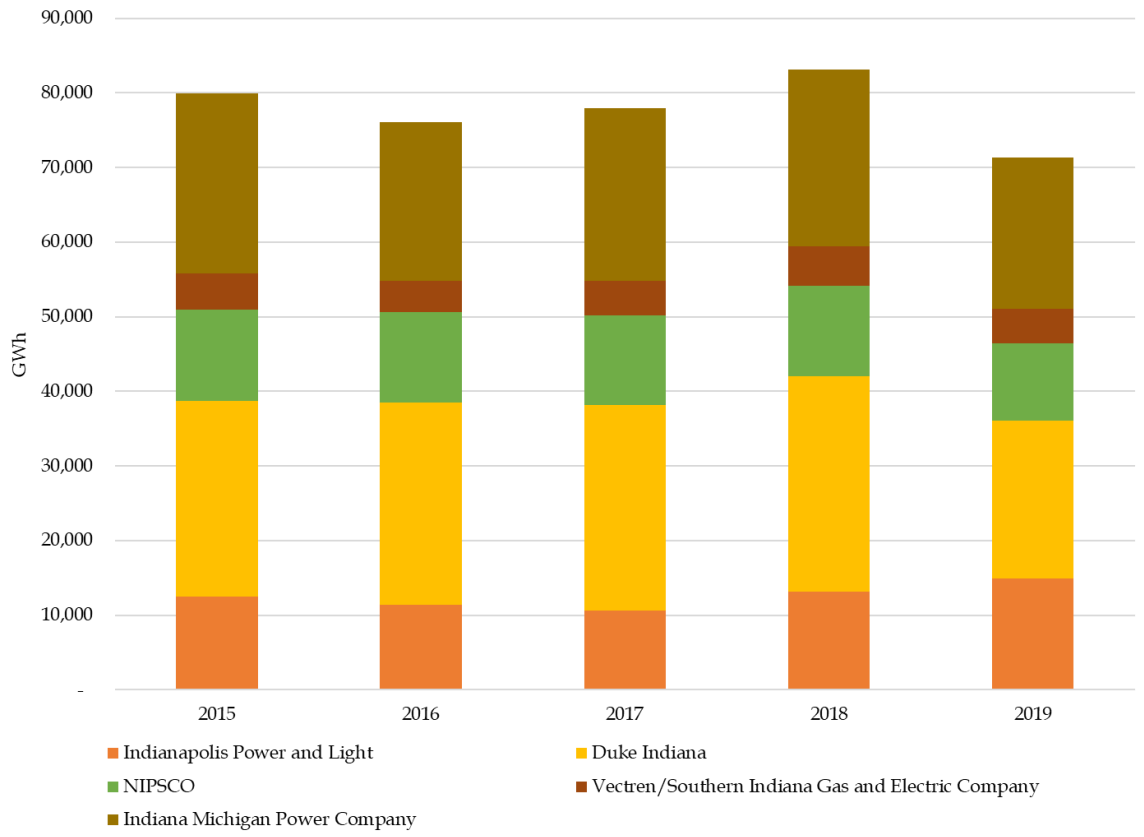
The Commission allows the IOUs to recover the costs and earn a return on the rate base of its generation assets. LEI assumes if the full revenue requirement of the generation assets cannot be fully recovered via the energy and capacity market, IOUs can recover the shortfall via the rate base capacity charge, which LEI also forecast and added in the blended electricity rates.

[246] Given the confidential nature of bidding information, LEI does not model strategic bidding activities including Fixed Resource Adequacy Plan offers (price taking resources).

LEI first calculated the revenue requirement of the generation assets owned by the IOUs. LEI reviewed financial statements of the IOUs,[247] and identified generation related gross and net plant-in-service values, generation asset related depreciation, non-fuel generation O&M costs, and generation related fuel costs. Then LEI calculated the revenue requirement using a cost-of-service model where the IOUs are allowed to earn the permitted WACC for such generation assets. LEI also reviewed the amount of energy generated from these IOU-owned generating assets to calculate a $/MWh revenue requirement.

Based on the most recent IRPs, IOUs do not intend to heavily invest in the existing assets, instead building mostly renewables. As generation assets retire, the book value of the retiring generation assets is removed from the revenue requirement calculation over time, and replaced by the value of newly built assets.[248]

Figure 102. Indiana IOUs net generation in the last five years (2015-2019)

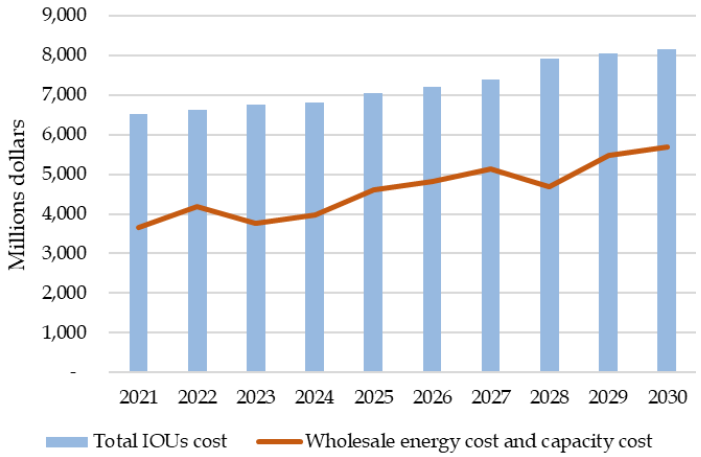


Source: Third party commercial database.

[247] Commercially available database based on FERC Form 1 data.

[248] Note: In the forecast, LEI assumes new renewables generation are not part of any IOU's net generation and are supported by a green rider. Planned new thermal generation owned by IOUs are also added in future IOU net generation.

Figure 103. Total IOU cost versus wholesale energy and capacity cost in Indiana (2021-2030)



Note: 'Total IOU cost' represents the cost to IOUs for providing energy, which includes both purchased energy and self-generation. The 'wholesale energy and capacity cost' represents the cost if IOUs procured energy and capacity entirely from the wholesale market instead.

Source: Third party commercial database; LEI analysis, July-August 2020 Continuous Modeling Initiative ("CMI") round.

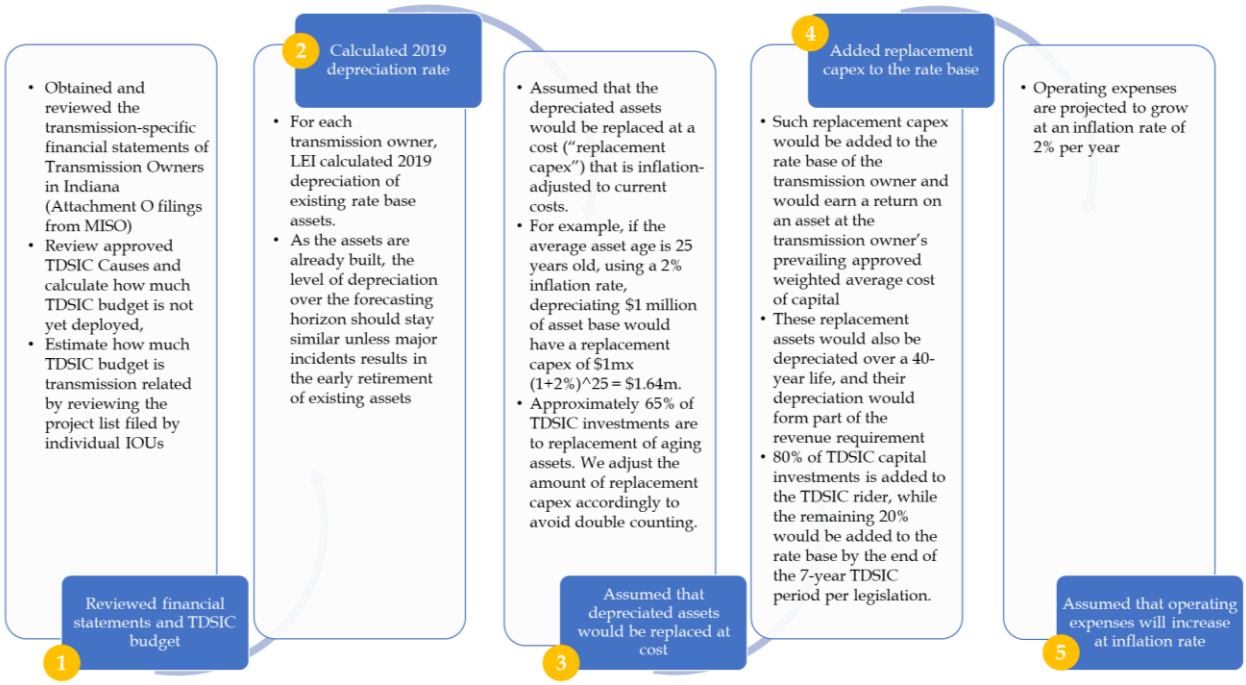
In each of the modeled years, LEI compared the forecast $/MWh Indiana wholesale energy and capacity market price against the $/MWh generation asset revenue requirement for the IOUs. This difference in $/MWh is then multiplied by the amount of generation from the IOUs, which results in the total dollar amount of rate base capacity carrying charge that is passed on to Indiana electric consumers.

8.5.4 Transmission rates forecast

There are various drivers of transmission rates. These include the level of rate base growth, replacement of old assets, and operating and maintenance expenses. As discussed in Section 5.2.2, transmission owners have financial ownership over the transmission assets, but have delegated control of transmission flows to the RTOs (MISO and PJM); this control includes the ability to develop an investment plan for the transmission system. The level of rate base growth is thus driven by MISO's Transmission Expansion Plan ("MTEP") and PJM's Regional Transmission Expansion Plan ("RTEP"). Transmission projects developed outside of Indiana may also impact the State's transmission rates if such projects are classified as Multi-Value Projects, or certain zones in Indiana are considered to be beneficiaries of Market Efficiency Projects.

Age also plays a role in transmission rates as owners will need to replace these assets at the end of their physical life to ensure reliability. O&M expenses, which constitute around one-third of the transmission revenue requirement, represent the cost of operating and maintaining the transmission assets, which include expenses such as maintenance of overhead and underground lines, computer hardware, station expenses, administrative and general expenses (salaries and wages, supplies), regulatory commission expenses, and general transmission plant maintenance. LEI forecast the transmission rate using the approach and assumptions shown in Figure 104.

Figure 104. Steps and assumptions used to forecast the transmission rate



Source: Attachment O filings from MISO, available in <https://www.misoenergy.org/markets-and-operations/settlements/to-rate-data/>

As stated in Section 8.1.2, Indiana Code 8-1-39 allows electric and natural gas utilities to submit infrastructure improvement plans covering a 5-7 years period, subject to IURC's approval. 80% of the capital investment costs associated with such infrastructure improvement plans are allowed to be recovered within the typical[249] seven-year planning period through a TDSIC surcharge, while the remaining 20% of the capital costs would be included in the utilities' rate base after the end of the planning period. LEI used the 80-20 split in its modeling as discussed below, where 80% of the capital cost of the TDSIC plan would be recovered within seven years, and the remaining 20% would be added to the rate base at the end of the 7-year period.

LEI reviewed the approved or settled TDSIC cases and isolated transmission and distribution capital investments based on publicly available data, where possible.[250] Approximately 36% of the approved $4.3 billion TDSIC plans capital investment, or $1.6 billion, are allocated for

[249] Although the legislation allows for plans covering a 5- to 7-year period, LEI observes that current TDSIC plans have been implemented using a 7-year planning horizon.

[250] Except for Indiana Michigan Power Company and Vectren South, all other IOUs provided an estimated breakdown between transmission and distribution capital investments in their TDSIC filings. Indiana Michigan Power Company currently does not have an approved TDSIC Plan since the IURC denied their request in 2015 (IURC Cause No. 4452). For Vectren South, we relied on major capital project budgets provided in Petitioner's Exhibit No. 2, Direct Testimony of Lynnae K. Wilson, Vice President of Energy Delivery on Description and Development of the TDSIC Plan, IURC Cause No. 44910.

transmission from 2016 to 2026.[251] As the main purpose of TDSIC is the replacement of aging assets, LEI considers the capital costs associated with TDSIC to be largely duplicative of the replacement capex mentioned in step 3 above. For example, based on LEI's review of the TDSIC proposed transmission projects of Vectren South,[252] replacement projects constitute approximately 65% of the estimated project costs for transmission. Therefore, in the transmission rate forecast, LEI adjusted the replacement capex and associated future depreciation of the replacement capex to reflect the TDSIC related capital investments in the near term,[253] and increased the rate base after the TDSIC plan by 20% of the TDSIC capital investment.

Finally, both MISO and PJM provide a long-term revenue requirement forecast based on their respective approved regional transmission expansion projects.[254,255] For MISO, the forecast covers the 2021 to 2034 period, while PJM's forecasts are 2021 to 2030. LEI relies on these forecasts to calculate the rate impact of non-TDSIC transmission expansion projects to Indiana ratepayers.[256]

Outside of the TDSIC projects, LEI expects any new projects would mainly be replacement projects to address issues arising due to aging assets, and as future load growth is forecast to be low. The main driver of most of the transmission projects in the MISO Central planning region, where Indiana is located, is the transmission asset's age. More specifically, the MISO MTEP 2019 stated that "to address age and condition and increase reliability across this region… there are also a number of load-driven projects across both Illinois, Indiana, and Kentucky."[257] In addition, only one of the top ten projects in the Central region is located within Indiana, which means there are limited new transmission projects in the State.[258] Based on the above, LEI projected the revenue requirements for transmission owners in the State, as shown in Figure 105.

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[251] Different utilities have different starting years for their TDSIC plans. Therefore, the combined capital investment spending period covers more than 7 years. Analysis is based on plans as presently approved and assumes that no subsequent TDSIC plans will be filed.

[252] Vectren South. Petitioner's Exhibit No. 2, Direct Testimony of Lynnae K. Wilson, Vice President of Energy Delivery on Description and Development of the TDSIC Plan, IURC Cause No. 44910.

[253] Some of the TDSIC capital investments that the IOUs are conducting may otherwise not have been spent if TDSIC did not exist.

[254] MISO. "Indicative Schedule 26 Annual Charges by MISO Pricing Zone for Approved Baseline Reliability Projects, Generation Interconnection Projects, Market Efficiency Projects and Targeted Market Efficiency Projects" July 22, 2020

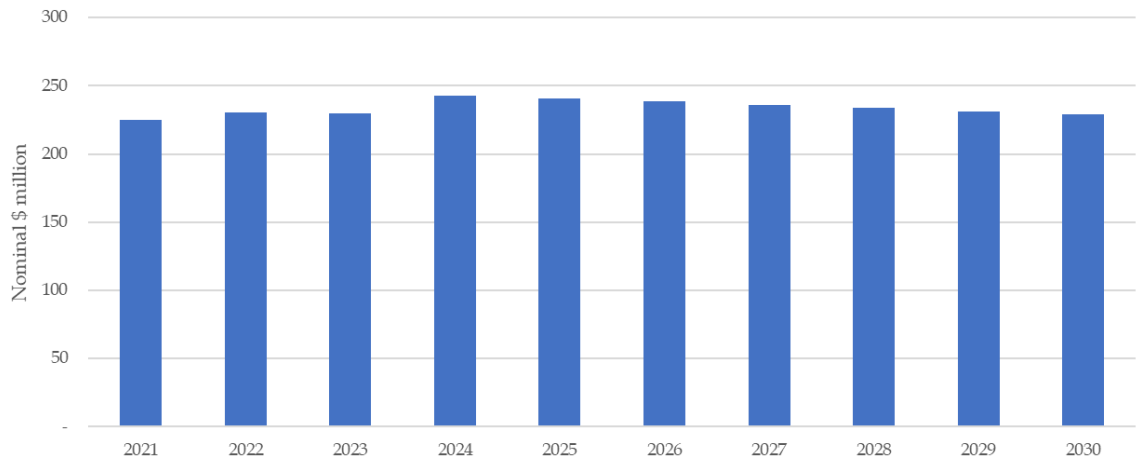
[255] PJM. "Project Status & Cost Allocations", Transmission Cost Information Center. <https://www.pjm.com/planning/project-construction>. Accessed September 10, 2020

[256] For Indiana Michigan Power, PJM's cost allocation only goes to transmission zone level, of which Indiana Michigan Power is within the AEP zone. LEI assumed the costs allocated to Indiana Michigan Power would be pro-rata to Indiana Michigan Power's rate base share within AEP.

[257] MISO MTEP 2019, page 53. Some MISO plans issued in 2020 show higher projected transmission investment.

[258] Ibid. Page 52 Figure 4.2-3.

Figure 105. Revenue requirement for regional transmission projects allocation



Sources: MISO Indicative Schedule 26 and 26A Annual Charges by MISO Pricing Zone for Approved Baseline Reliability Projects, Generation Interconnection Projects, Market Efficiency Projects, and Targeted Market Efficiency Projects; PJM Transmission Cost Information Center; LEI analysis

In addition to the revenue requirements required to cover the carrying costs of the fixed assets invested by the transmission owners, the O&M costs of operating the transmission grid, and the socialized costs of regional network upgrades, the MISO transmission tariff also includes charges to recover the costs to provide scheduling, system control and dispatch service (Schedule 1 of MISO transmission tariff), and reactive supply and voltage control from generation sources service (Schedule 2 of MISO's transmission tariff). PJM also has similar charges to its customers.[259] In 2020, the scheduling charge and the reactive supply and voltage control charge accounted for 2.8% and 5.9%, on average, of MISO's transmission charges, respectively. LEI's projection assumes that the scheduling charge would grow at the inflation rate, while the reactive supply and voltage control charge would rise in line with the energy price changes, as cost drivers of providing reactive supply and voltage control are similar to those driving energy market costs. Other rate riders not covered under the transmission tariff are discussed in Section 8.5.6.

Given all of the above, LEI forecast the transmission owner blended transmission rate for the next ten years. Figure 106 shows the forecast transmission rate in $/MWh. In the near term (through 2026), LEI forecasts a transmission rate increase as the TDSIC rate rider continues to grow, and the impacts of approved MTEP projects continue to materialize. However, all existing TDSIC rate riders are expected to expire by 2026 (unless Indiana Michigan Power obtains approval for its TDSIC proposal), and after that, LEI expects capex to return to following a replacement cost level. Therefore, over the next ten years, if no new major transmission projects are approved, the total transmission revenue requirements for all transmission owners combined are expected to increase at a CAGR of 2.1%. Peak load in Indiana is forecast to grow at a CAGR of slightly less

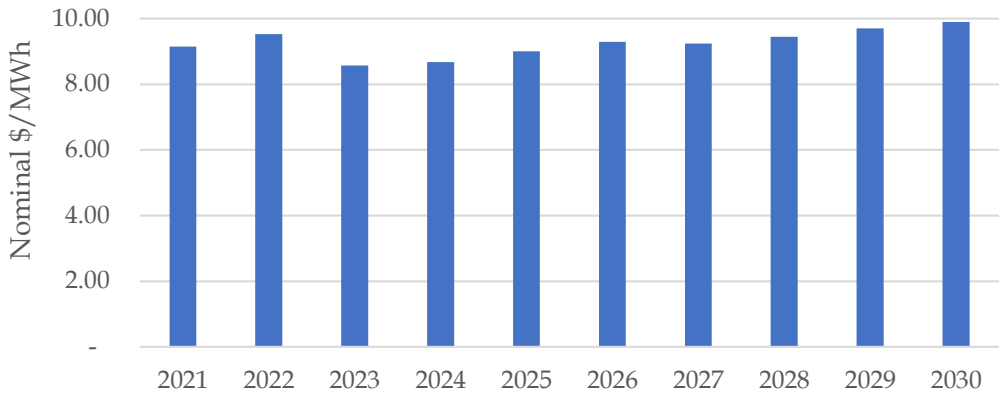
[259] PJM Scheduling, System Control & Dispatch Service is covered in Tariff Schedule 1, 9-1 to 9-6. Reactive Supply and Voltage Control from Generation and Other Sources Service is covered in Tariff Schedule 2, Regulation and Frequency Response Service is covered in Tariff Schedules 1.3.2.2 to 1.3.3.2A.

than 1% in the next ten years, and the energy demand is forecast to grow at a CAGR of 1.2%. This means that transmission rates on a $/MW-year or $/MWh basis would increase at CAGRs of 1.2% and 0.9%, respectively, over the next ten years.

It should be noted that the above forecast transmission rate is a blended transmission rate of the transmission owners in Indiana,[260] and electricity ratepayers located in service territories of specific transmission owners may face very different transmission rate trajectories due to various drivers such as the TDSIC planning period, allocation of MISO/PJM regional transmission project costs, and age of existing assets.

Furthermore, the year-over-year rate change may be smoother than our forecast trajectory as the TDSIC rate increases are limited to no more than 2% of a utility's total retail revenues.[261] This limitation may result in shifting rate changes across the years, leading to a smoother rate increase over a longer period of time.

Figure 106. Forecast Indiana transmission owner blended transmission rate (2021-2030)



Note: AEP in PJM consists of Indiana Michigan Power Company and AEP Indiana Michigan Transmission Company ("I&M Transco"). I&M Transco does not provide retail services to customers within Indiana. Instead, I&M Transco is focused only on providing wholesale transmission service. Only the Indiana Michigan Power Company revenue requirement was included in this calculation as the focus is on retail rates.

Source: LEI analysis

8.5.5 Distribution rates forecast

While transmission tariffs are charged by the transmission owners, which are all under FERC and IURC jurisdiction, distribution tariffs are less uniformly regulated in Indiana, as entities that charge distribution rates include IOUs, munis, and REMCs. As noted in Section 6.1.1, all IOUs

[260] Using total forecast revenue requirement of the transmission owners divided by total forecast energy demand.

[261] Indiana Code 8-1-39.

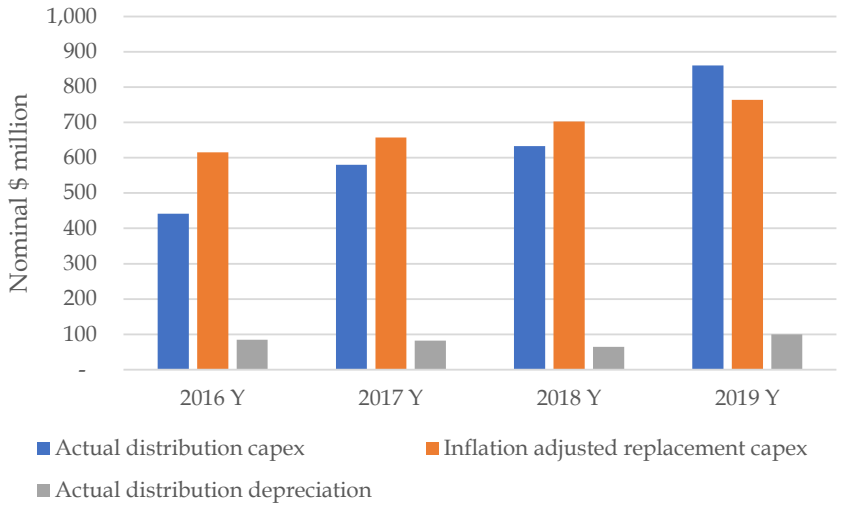
are presently regulated by the IURC, but only ten out of 77 municipalities are under IURC jurisdiction.[262] Finally, none of the REMCs are regulated by the IURC.

Similar to how LEI projected the transmission rates, IOU distribution rates were forecast using a cost of service approach. LEI first reviewed utility regulatory financial data and calculated each utility's revenue requirement based on their existing rate base, depreciation, expected capex, and O&M expenses.

Before presenting the distribution rate forecast, it is important to consider several points arising from review of IOUs' historical distribution financial data:

- The distribution rate base has been growing rapidly. The 5-year CAGR of the total distribution net plant in service was 11.2%, driven by the high level of capex relative to depreciation. However, after taking into account the age of existing assets and the inflation-adjusted cost to replace such assets,[263] the level of capex in recent years is in line with LEI's estimated inflation-adjusted replacement capex, as shown in Figure 107.

Figure 107. Historical distribution capex vs. estimated inflation-adjusted replacement capex in Indiana (2016-2019)



Source: LEI analysis, third party commercial database based on FERC Form 1 data.

- As the age of existing distribution assets is high, the dollar value of assets depreciated each year is low relative to the cost to replace such assets after adjusting for inflation. This led to a high rate base growth rate, which is expected to continue in the future.

[262] <https://www.in.gov/oucc/2468.htm>. Accessed on September 11, 2020.

[263] Age of fixed assets can be estimated using value-accumulated depreciation divided by annual depreciation. LEI estimated that the value-weighted average age of Indiana IOU distributed assets was 69 years old. LEI assumed a 2% historical and long-term inflation rate.

- LEI has also observed that the O&M costs of the distribution business of the IOUs have grown at a high CAGR of 9.7% in the past five years. This is significantly higher than inflation. Such increases are mainly driven by the growth in the maintenance cost of overhead lines.[264]

Going forward, the main driver of investments in distribution assets are the TDSIC incentives, as discussed in Section 8.1.2. TDSIC expenses are associated with modernizing the Indiana grid to replace aging assets, improving reliability and deliverability, and enabling the integration of more renewable generation, energy storage facilities, and electric vehicles.[265] Based on approved TDSIC plans, total capital investments for TDSIC-related distribution projects would amount to $2.8 billion between 2016 and 2026, accounting for 64% of the total TDSIC capital investment amount. Out of this $2.8 billion, approximately $900 million has already been invested or had its investment costs included in TDSIC rate riders between 2016 and 2020. Therefore, a remaining $1.9 billion would have to be recovered from 2021 to 2026.

Maintenance of overhead lines will continue to drive IOU distribution operating expenses, as the utilities strive to meet reliability targets. As TDSIC projects replace old assets with newer, more reliable assets, LEI does expect the future distribution O&M growth rate would be lower than the historical growth rate of over 9%. While savings may vary, LEI has assumed an approximately 25% savings, so the average distribution growth rate is modeled to be 7% over the modeling period. Well structured PBR rate designs may allow for further savings.

Given the above assumptions, LEI forecast average Indiana IOU distribution rates, as presented in Figure 108. Over the next ten years, IOU distribution revenue requirements are forecast to increase at a CAGR of 4.1%. Given the 1.2% per annum forecast load growth over the same period, the distribution rate (in $/MWh terms) is projected to grow at a CAGR of 2.9%.

The actual timing of distribution rate changes largely depends on when a rate case is filed by the utility and when IURC approves it. If the IURC has recently approved a utility rate case, it is unlikely that another rate case would be filed in the near future unless extraordinary circumstances arise. For example, Duke Energy Indiana and Indiana Michigan Power's most recent rate cases were approved in 2020. Therefore, the level of certainty of near-term distribution rates for these two utilities is high. In contrast, Vectren South's most recent approved base rate case was filed in 2009 and approved in 2011.[266]

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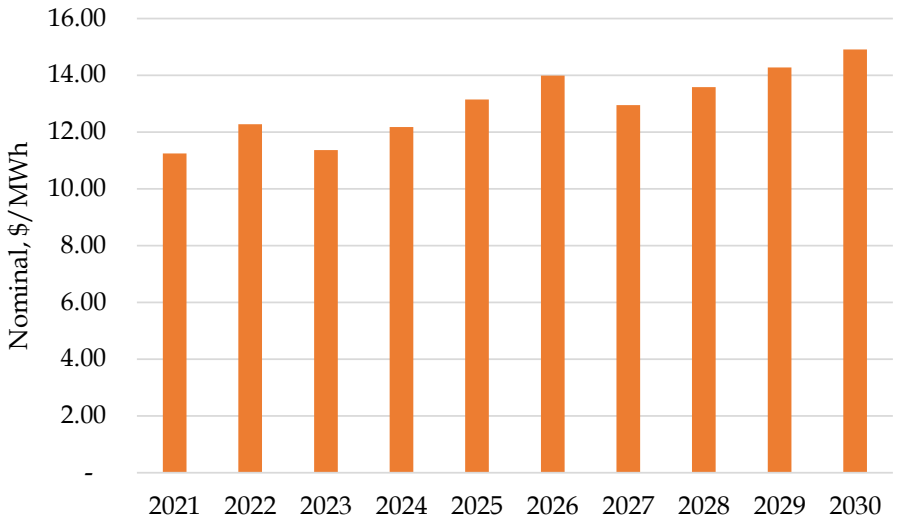
[264] Based on LEI's review of financial statements of the IOUs, increase in overhead line maintenance expense accounts for 90% of the distribution O&M cost increase for I&M from 2015 to 2019, 84% for NIPSCO, 82% for IPL, and 44% for Duke Energy Indiana. By comparison, Vectren has a relatively small distribution O&M cost increase and overhead line maintenance cost stayed flat in the same period.

[265] See IURC Cause No. 44910 Petitioner's Exhibit No. 2 (Vectren TDSIC filing), IURC Cause No. 45253 Petitioner's Exhibit 1 (Duke Energy Indiana TDSIC filing), NIPSC 2016 Integrated Resource Plan.

[266] IURC Cause No. 43839.

Figure 108. Indiana IOUs' forecast average distribution rates (2021-2030)



Source: LEI analysis

8.5.6 Forecasts of the riders

In Indiana, in addition to the cost of energy purchase and revenue requirement for transmission and distribution services, ratepayers also pay for rate riders used to fund approved projects or initiatives such as adjustment charges for regional transmission organization costs, charges for resource adequacy, fuel cost adjustment riders, Demand Side Management Adjustment Mechanisms, a Green Power Rider, and Adjustment Charges for Federally Mandated Costs, as discussed in Section 6.3.6.

To avoid double-counting, LEI considered the following riders to be already covered in the energy and capacity price forecasts, transmission rate forecasts, or distribution rate forecasts:

- **Fuel cost adjustment riders** – these are embedded in our energy price forecast;
- **Adjustment charges for regional transmission organization** – covered in the transmission rate forecasts; and
- **Charges for resource adequacy** – included in the capacity price forecast.

On the other hand, LEI forecast the demand-side mechanism rider, green energy rider, and the Federally-mandated cost adjustment. Figure 109 provides a description of how these riders were projected.

In 2021, these rate riders combined amount to $7.1/MWh, or approximately 7% of the total end-user electricity rate, and rise to $13.3/MWh by 2030, or 11% of the total end-user electricity rate. This implies an annual growth rate of 7.2% over the next decade.

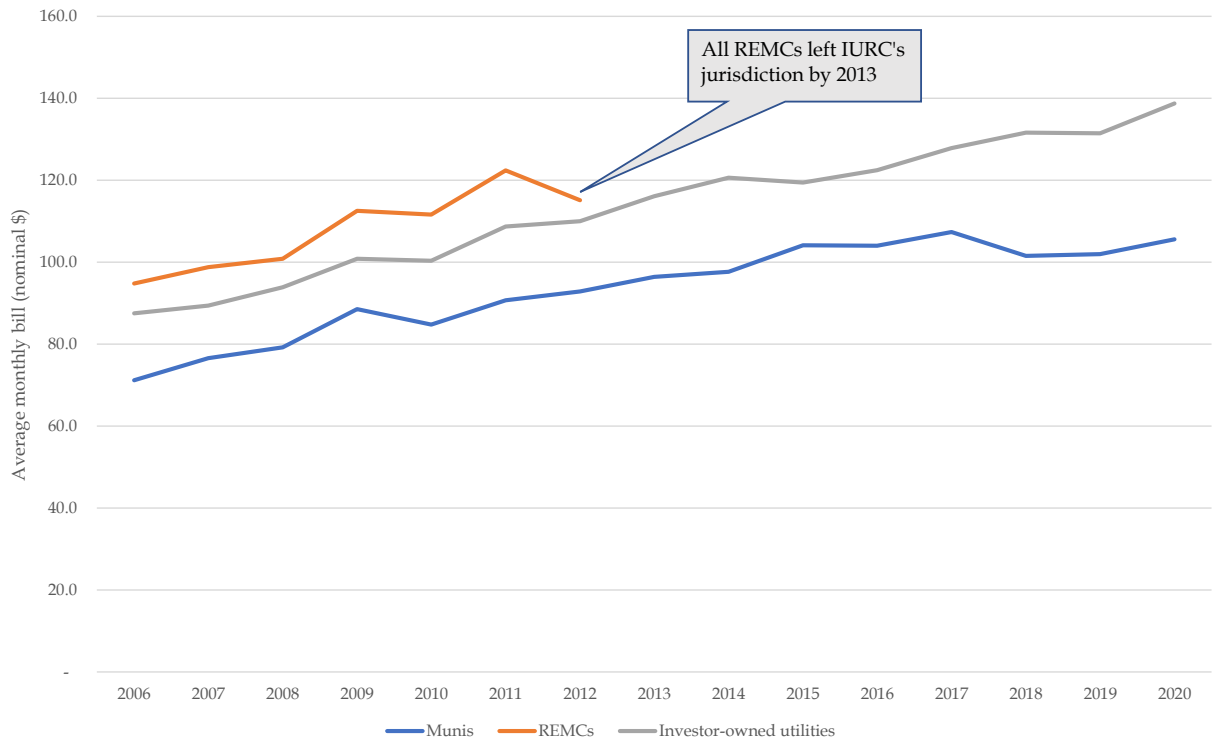
Figure 109. Forecast riders

Riders	
1) Demand side mechanism rider	LEI scaled this with the energy efficiency growth rate used in the energy forecast.
2) Green energy rider	This rider changes over time based on two factors: namely, the capacity of wind and solar added, and the associated subsidy needed. LEI expects the levelized cost of wind and solar to decline over time, and therefore the level of subsidy required for each MW of new wind and solar would decline. However, units that are already built and will be built during the forecasted horizon will continue to require subsidies (difference between their levelized cost of energy and the energy plus capacity market revenue) for their accounting life. Therefore, the Green Energy Rider increases over time.
3) Federally-mandated cost adjustment	As stipulated in the Indiana Code Title 8 Section 7, this charge allows utilities to recover 80% of the costs associated with approved projects to comply with federal mandates, including annual operations and maintenance expenditures. As of 2020, this is a very small portion (< 1%) of the end-user electricity rate. LEI forecasted that this rate would grow at inflation as new federal mandates such as environmental requirements and cyber security would lead to new projects replacing existing federally mandated projects. (For example, IURC's Indiana Utility Guide listed Federally Mandated Cyber Security Cost and Federally Mandated Environmental Cost as the two federally mandated capital investment trackers)

8.6 Comparing rates between utility types

IURC has conducted an annual Electricity Residential Bill Survey since 2006. The survey collects the July 1st bill in each year allocable to simple tariff residential customers with 500, 1000, 1500, and 2000 kWh monthly consumption levels for utilities under IURC jurisdiction. Historically, the simple average monthly bill for munis has been lower compared to IOUs and REMCs for all residential customers of all four consumption levels. Figure 110 compares the average monthly bill for 1000 kWh residential customers of IOUs, munis, and REMCs based on the IURC rate survey data.

Figure 110. Historical simple average monthly bill of a 1000 kWh residential customer in Indiana by utility type



Source: IURC 2006 – 2020 Residential Bill Survey

The IURC Residential Bill Survey only covers the utilities under IURC's jurisdiction, and the number of utilities under IURC's jurisdiction declined from 25 in 2006 to 13 in 2020, with all four REMCs and seven out of 16 IURC jurisdictional munis leaving the IURC jurisdiction. As presented in Figure 110, REMCs were, on average, the most expensive utility type (for 1,000 kWh residential customers) before they all left IURC's jurisdiction. In fact, if we look at the REMCs' monthly bill individually, they rank amongst the second to fifth most expensive among the 23 utilities surveyed in 2011 (before the REMCs started leaving IURC's jurisdiction).

This observation suggests that the more expensive utilities in the State are not included in the survey. We further investigated such potential bias by comparing the munis that left IURC jurisdiction, and found that among the seven munis that left IURC's jurisdiction, two were ranked as the most expensive utility for the 1000 kWh residential monthly bill the year before they left, and one is the second most expensive utility in the year before it left. Furthermore, another muni was the most expensive for the 500 kWh category the year before it left IURC jurisdiction. In contrast, two utilities that left IURC's jurisdiction were the cheapest muni the year before they left. Given the offsetting characteristics of the munis which are no longer in the Survey, it is possible that an average muni would have a charge that is closer to an average IOU than is shown in the IURC Residential Bill Survey. The historical electricity rates discussed in Section 7.1 also showed that the difference between the IOUs' average electricity rates and munis was only 1.5% per year from 2012-2018. Therefore, the forecast electricity rates for munis would likely be slightly

lower than the projected average IOU electricity rates discussed in this section. On the other hand, LEI anticipates that the average REMC electricity rates would continue to be higher than the forecast electricity rates for IOUs.

Key takeaways

- Electricity prices in Indiana have increased at a CAGR of 2.9% over the 2010-2019 period. According to rate cases filed by the State's regulated electric utilities, this increase has primarily been driven by:
  - flattening demand following the global financial crisis, which has translated to higher rates as the fixed costs of providing electric service are spread across a shrinking customer base;
  - a growing need to replace and maintain aging infrastructure, which has been incentivized partly by the TDSIC tracker (with current TDSIC plans amounting to $4.3 billion in approved investments); and
  - investments in environmental retrofits to comply with Federal regulations, which totaled $4.5 billion over the 2010-2020 timeframe, and included projects such as installing pollution control equipment and converting coal units to gas.
- Going forward, there will be upward pressure on electricity prices stemming from: evolving environmental regulations; the expansion of energy efficiency efforts, and the emergence of DERs (both of which reduce system demand). On the other hand, there will be downward pressure on electricity prices from factors such as low natural gas prices, and the declining costs of renewables (particularly wind and solar).
- LEI forecasts that the IOUs' blended electricity rates in the next 10 years will increase at a CAGR of 2.0%. The projected capacity prices and the riders are forecast to push up the electricity prices. The forecast growth is lower than the historical electricity rate growth from 2010-2019.

9 Other considerations

There are several emerging energy-related issues at the national and state level. Some of these include: emerging debates around natural gas bans; the potential growth in load due to electrification; the carbon life cycle impacts of various generation resources; the directional path for coal-fired generation going forward; issues around renewable energy siting; energy efficiency; and uncertainty around the impacts of COVID-19. This section provides a high-level, but non-exhaustive, discussion of these issues, as requested in the ICCF's RFP.[267]

9.1 Natural gas bans

Natural gas usage bans are an emerging issue in certain states, particularly in relation to emissions reductions and decarbonization efforts. Activity in this area has largely been focused on banning the usage of natural gas in new buildings (e.g., for heating and cooking purposes) and pushing for building electrification (also covered in Section 9.2). In July 2019, Berkeley, California became the first city to move forward with such a ban, after the city updated its building code to prohibit natural gas infrastructure in new buildings.[268]

Since then, a small number of municipalities have followed suit with similar bans on natural gas hookups for new buildings. Others have taken less stringent approaches with the same ultimate goals of reducing/eliminating the usage of natural gas and pushing for all-electric energy supply for new buildings. These include: focusing on banning the usage of natural gas for heating purposes only (not cooking) in new construction buildings; allowing mixed-fuel supply (electricity and natural gas), but requiring higher energy standard achievements than electricity-only buildings; and incenting the usage of heat pumps over gas-based home heating systems through the usage of rebates.[269] Local pushes towards direct natural gas usage reduction at the residential and commercial levels have been seen in cities located in California, New York, Massachusetts, and Washington.

As a direct counter to local government efforts seen in certain states to ban the usage of natural gas, a handful of other states have passed or introduced laws meant to prohibit local governments from adopting similar electrification measures that would effectively ban or hamper the usage of natural gas. Figure 111 shows those states where governments have passed or introduced legislation prohibiting local measures meant to block access to utility service based on fuel type, as well as those states where local governments have put forward effective gas bans for new buildings.

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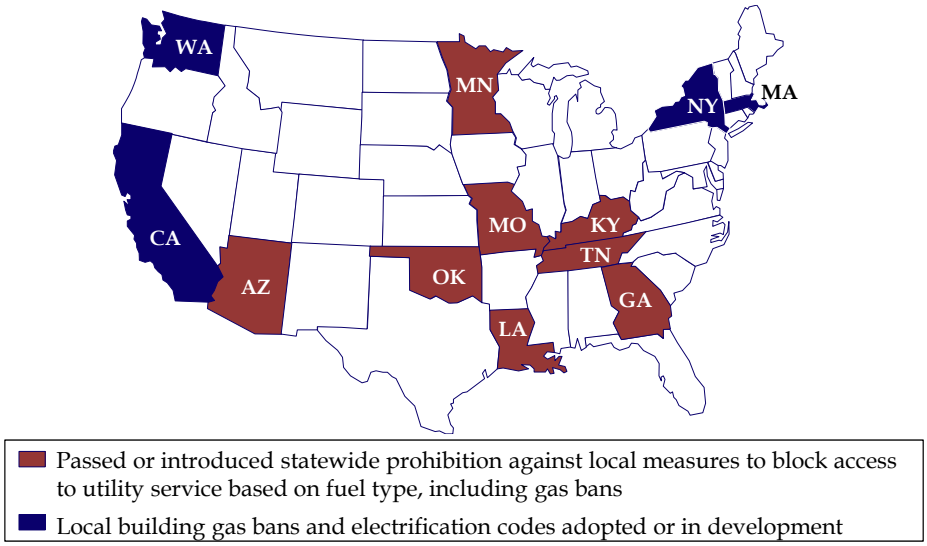
[267] Notably, although the topics of electrification and COVID-19 impacts were not included in the RFP, these were mentioned by stakeholders during multiple virtual meetings.

[268] City of Berkeley. *Ordinance No. 7,672-N.S., Adding a New Chapter 12.80 to the Berkeley Municipal Code Prohibiting Natural Gas Infrastructure in New Buildings Effective January 1, 2020*. July 16, 2019.

[269] DiChristopher, Tom. S&P Global Market Intelligence. *'Banning' natural gas is out; electrifying buildings is in.* July 8, 2020.

Figure 111. States advancing or prohibiting building gas bans and electrification codes



Source: DiChristopher, Tom. S&P Global Market Intelligence. *'Banning' natural gas is out; electrifying buildings is in*. July 8, 2020.

While the natural gas ban activity discussed previously relates to new buildings, in the longer term, activity to reduce the usage of natural gas as a direct fuel source will eventually shift to focus on existing commercial and residential buildings as well. This could occur implicitly through aggressive emissions reductions targets set by certain states, including New York, New England, and New Jersey, which would likely require a reduction in the usage of natural gas for heating purposes in some form. It could also occur through more direct policy; for example, as part of Los Angeles' plan for achieving longer-term carbon neutrality, the city has set a goal of operating all buildings with clean power by 2050.[270] Similarly, in New York City, Mayor Bill de Blasio announced in February 2020 a proposal of ending usage of natural gas and other fossil fuels in large building systems by 2040 (as well as stopping any new infrastructure that expands the supply of fossil fuels in the city).[271]

Implications of this activity in Indiana will depend on whether similar actions to ban the usage of natural gas begin to occur at the local, State, or Federal level. LEI is not aware of similar actions to ban the usage of natural gas gaining traction at the local or State level in Indiana. Similarly, at present, no Federal policy has been advanced with a similar aim of the natural gas usage bans that have been discussed previously. However, the Biden-Sanders unity taskforce recommendations on "combating climate change" from August 2020 included the proposition of setting a "national goal of achieving net-zero greenhouse gas emissions for all new buildings by 2030, on the pathway to creating a 100 percent clean building sector."[272] This suggests there is potential for the conversation to shift to the Federal level in the longer term. Aside from direct implications, pipeline utilization rates could also fall if natural gas bans become

[270] Mayor Eric Garcetti. *L.A.'s Green New Deal: Sustainable City pLAn*. 2019

[271] NYC Office of the Mayor. *State of the City 2020: Mayor de Blasio Unveils Blueprint to Save Our City*. February 6, 2020

[272] Biden-Sanders Unity Task Force Recommendations. *Combating the Climate Crisis and Pursuing Environmental Justice*. August 2020

more prevalent outside of Indiana, which would put upward pressure on costs of natural gas delivery. On the generation side, longer-term moves towards emissions reductions in the electricity industry would directly impact natural gas-fired generation. States such as New York, Maine, and most recently Illinois have put forward legislation, executive orders, or goals of moving towards 100% renewable or non-emitting energy in the next two to three decades – meaning traditional fossil-fuel fired resources, including conventional natural gas-fired generation, could be phased out eventually. Assuming large-scale moves away from natural gas-fired generation materialize in the medium to long-term, issues around stranded costs could emerge, leading to potential issues around new-build of gas-fired resources.

Combined with other rapid changes occurring in the industry, the potential for stranded costs has implications around planning for new-build gas-fired resources today. In one recent example, the IURC denied Vectren's proposal to build an 850 MW CCGT plant, after concluding that "the proposed large scale single resource investment for a utility of Vectren South's size does not present an outcome which reasonably minimizes the potential risk that customers could sometime in the future be saddled with an uneconomic investment or serve to foster utility and customer flexibility in an environment of rapid technological innovation."[273]

Longer-term potential alleviation of stranded cost issues through alternate supply resources

Renewable natural gas and hydrogen present two potential longer-term alternatives to conventional natural gas with the potential to reduce stranded cost concerns. Renewable natural gas is considered a carbon-neutral energy source, while hydrogen can be carbon-neutral when renewable electricity is used to produce hydrogen gas via electrolysis.

Importantly, both renewable natural gas and hydrogen can take advantage of existing conventional natural gas infrastructure. For hydrogen gas, existing natural gas-fired generation infrastructure can be converted to run on hydrogen, albeit at some incremental capital costs. For renewable natural gas, as it is fully interchangeable with conventional natural gas,[274] it benefits further from being able to utilize the same pipeline infrastructure used to transport conventional natural gas.[275]

There are a number of obstacles that could prevent the advancement of these energy supply options, including issues around production costs, scalability, and accessibility. However, assuming continued development of these two alternatives, increased scalability, and improving cost-competitiveness, they could present utilities with the potential to reduce stranded costs related to natural gas infrastructure in the longer term.

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[273] Indiana Utility Regulatory Commission. Order of the Commission for Cause No. 45052. Approved April 24, 2019.

[274] US DOE's Alternative Fuels Data Center. Renewable Natural Gas Production. Accessed September 2, 2020.

[275] NREL. *Energy Analysis: Biogas Potential in the United States.* October 2013. (Which states, "upgraded biogas is comparable to conventional natural gas, and thus can be injected into the pipeline grid or used as a transportation fuel in a compressed or liquefied form.") p. 1.

Key takeaway

Natural gas usage bans are an emerging issue in certain states that could have longer-term implications for Indiana if the conversation shifts to the Federal level. Natural gas delivery costs could also increase due to lower pipeline utilization rates. Electrification of heating may increase electricity demand (discussed subsequently in Section 9.2) but increases vulnerability to outages.

Changing electricity system dynamics have also led to discussions around the potential for stranded costs associated with large new-build gas-fired generation resources in the longer-term.

9.2 Electrification

Electrification is another area that presents the potential for significant changes in the medium to longer term. In particular, high electrification scenarios could lead to a need for additional generation resources, and may require management policies to deal with changing consumption patterns. While electrification can be broad in focus, the two main areas that are often identified for potential electrification are heating (typically as a replacement of natural gas or fuel oil) and transportation. As mentioned previously:

(i) Around 30% of Indiana households rely on electricity as a primary energy source for home heating, and Indiana is not one of the states that has seen strong moves towards natural gas usage bans/electrification of heating; and

(ii) there are currently no government-level incentives in Indiana for electric vehicles.[276]

The likelihood of a high-electrification future materializing in the medium to longer term will depend on a number of factors (e.g. declining costs for heat pumps, declining cost for battery storage) as well as policies that push for electrification, and is by no means guaranteed.

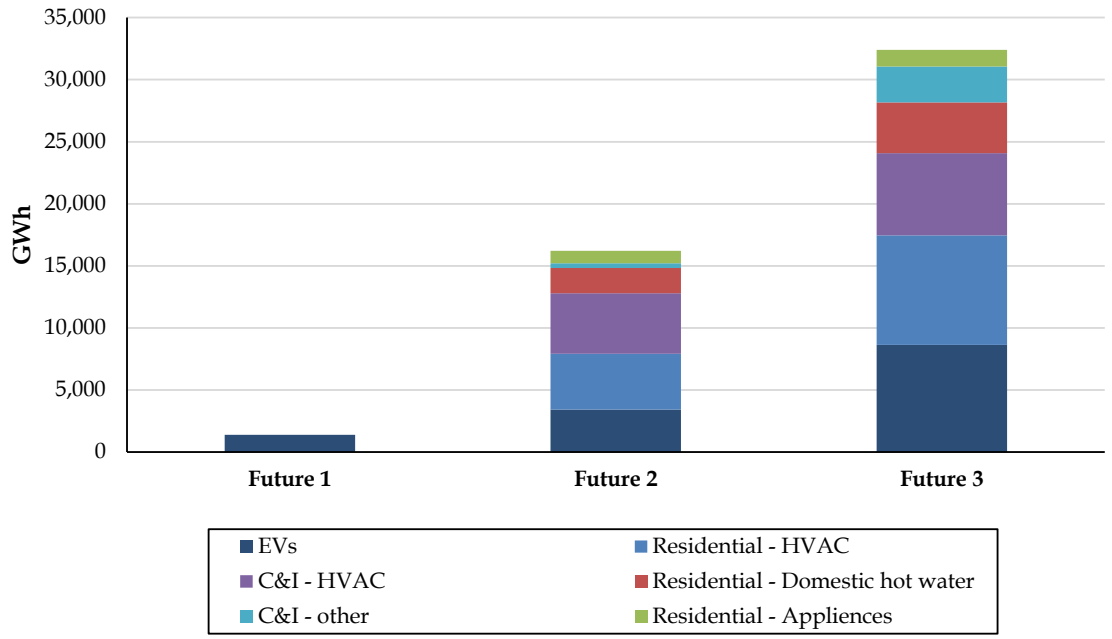
To illustrate the potential longer-term implications of electrification on electricity consumption, Figure 112 presents electrification-driven consumption for 2040 from MISO's 2020 Futures Whitepaper (information is presented for LRZ-6, which encompasses the vast majority of Indiana and a small portion of Kentucky). As is visible through the figure, electrification presents an area of large uncertainty with respect to electricity consumption. Compared to the low electrification scenario (Future 1), futures with higher penetration of EVs and electrification of heating lead to significant increases in energy consumption. In terms of total consumption, Future 2 and Future 3 lead respectively to 13% and 26% higher energy consumed in 2040 compared to Future 1.

Assuming a high electrification scenario materializes, numerous market changes would emerge aside from the growth in energy consumption that would need to be addressed. Related to the electrification of heating, relative seasonal consumption patterns could change, and the system could move to high winter-peaking as electricity usage ramps up during colder months. Related to the electrification of transportation, and EVs in particular, the average hourly consumption

[276] Plug In Midwest. *Midwest Incentives.* <http://www.pluginmidwest.org/midwestincentives/>

patterns are likely to change; importantly, without thoughtful approaches to managed charging, peak demand levels could rise significantly. Responses to these issues, should they emerge, can range from actively and intensely looking at options available such as policy and rate design changes, to allowing the market to decide the best response.

Figure 112. 2040 outlooks for electrification in LRZ-6 under three future scenarios (GWh)



Source: MISO. *MISO Futures Whitepaper: MTEP 21.* April 27, 2020.

Key takeaway

Electrification is another area of significant uncertainty that **could** lead to large upside growth in electricity consumption, peak demand, and changes to consumption patterns. Heating and transportation applications are the largest areas of potential growth in electrification for Indiana. High electrification scenarios would likely require the need for new-build of generation capacity in the longer term, although managing consumption could reduce the overall need for this new capacity.

9.3 Carbon and life cycle impacts of coal, natural gas, solar, and wind

When considering the climate impact of new generation resources, it is helpful to get a more comprehensive understanding of the total emissions estimates associated with different technology types over their entire life cycles, rather than only the emissions that occur during the generation process.

The life cycle environmental impacts of various generation technologies can be assessed through a Life Cycle Assessment ("LCA"), which is meant to account for all stages of a project's life. LCAs are typically focused on greenhouse gas ("GHG") emission estimates for specific technology

types, as measured by CO_2 equivalents ("CO_2e") per kWh.[277] Project life can be broken down into three stages: **upstream**, which essentially relates to the construction stage; **operation** over the project's lifetime; and **downstream** (decommissioning and other related work carried out after the project's end-of-life). For fossil-fuel fired technologies, the life cycle impact includes resource extraction and delivery for combustion purposes to generate electricity, which can be included in the operation stage of the LCA.

Figure 113 shows the various high-level stages considered in an LCA along with their main components, as well as estimates for the associated shares of emissions per stage for wind, solar, and coal-fired generation.

Figure 113. Life cycle assessment stages and estimated emissions shares by component

Life cycle stage	Upstream	Operation	Downstream
	▪ Raw materials extraction (for use during construction stage) ▪ Construction materials manufacture ▪ Components manufacture (e.g. solar modules, turbines, other components) ▪ Power plant construction	▪ Fuel cycle (for coal/gas, includes resource extraction, treatment/ processing, transportation /delivery) ▪ Combustion for power generation (coal/gas) ▪ Operations and maintenance	▪ Dismantling ▪ Decommissioning ▪ Disposal and recycling ▪ Land rehabilitation

Estimated share of emissions attributable to each life cycle stage (percent)			
Wind	~86%	~9%	~5%
Solar	~60% - 70%	~21% - 26%	~5% - 20%
Coal	<1%	>98%	<1%

Sources: NREL's *Life Cycle Greenhouse Gas Emissions from Solar Photovoltaics* and *Wind LCA Harmonization* fact sheets

As shown in the figure, for **coal-fired generation** technologies, the vast majority of emissions occur during the operational stage, which includes coal extraction and transportation, coal combustion for generation purposes, and ongoing operations and maintenance of the generation facilities. The portion of total emissions associated with upstream and downstream processes are comparatively minimal. **Gas-fired resources** would exhibit similar breakdowns, with the vast majority of emissions occurring during the operation stage. In general, gas-fired generating resources would have higher efficiency levels than coal (i.e., lower emissions per kWh of electricity produced), although methane leaks have been an ongoing concern associated with gas during the fuel cycle (during both the extraction and delivery process). Methane leakage concerns

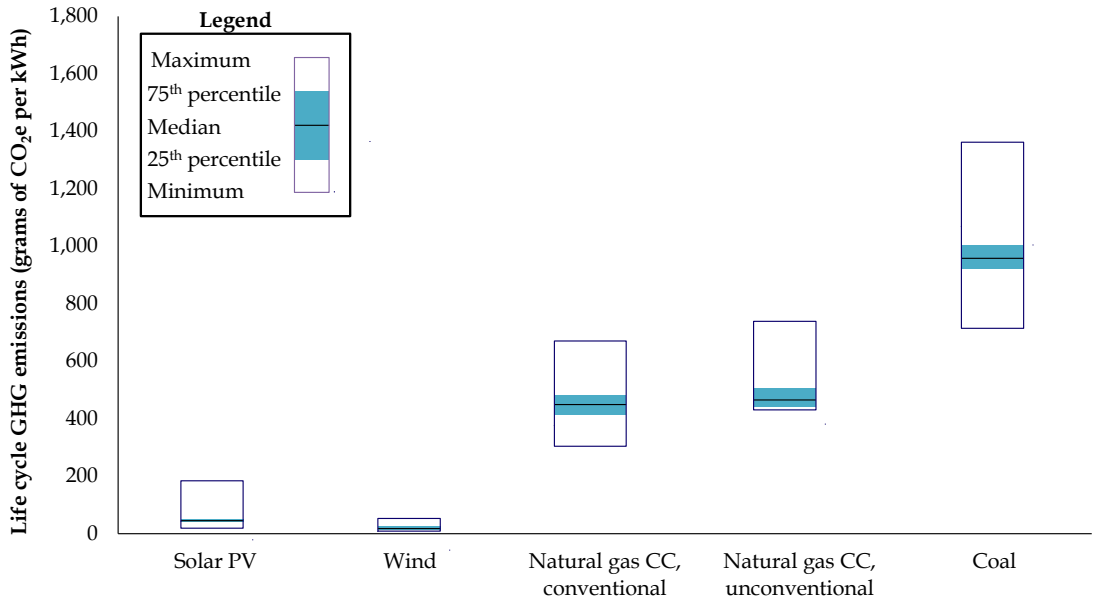
[277] CO_2e is a measurement used to standardize the various greenhouse gases (including carbon dioxide, methane, nitrous oxide) into a single comparable unit.

are higher for shale gas, though the industry appears to be increasing its efforts to address the issue.

For **wind** and **solar resources**, the majority of emissions occur during the upstream stage (project construction and associated works). Solar and wind are considered non-emitting renewable resources, and do not emit greenhouse gases as a byproduct during the electricity generation process. Therefore, emissions during the operation stages are low, although some are incurred related to operating and maintenance activities (e.g., equipment replacement and transportation). Some emissions also occur in the decommissioning stages following end-of-life for the facilities.

While LCA is a useful method for estimating total emissions associated with specific technology types, there are a number of issues that have led to wide-ranging LCA estimates, which can be attributed to differences in the methodologies and assumptions used. In an attempt to enhance precision across various LCA estimates, the National Renewable Energy Laboratory ("NREL") led an LCA harmonization process using a large number of LCA studies (over 2,000) to help in "clarifying inconsistent and conflicting estimates in the published literature, and reducing uncertainty."[278] Results from NREL's LCA harmonization process are presented in Figure 114 for the following technologies: solar PV, wind, natural gas (combined cycle), and coal. As NREL's harmonization process involved a review of a large number of studies, results are presented as a range that includes the median LCA estimate, the 25th and 75th percentiles, and the minimums and maximums.

Figure 114. Range of estimates for life cycle GHG emissions by resource type (CO_2e per kWh)



Source: NREL presentation. *Environmental Impacts of Renewable Electricity Generation Technologies: A Life Cycle Perspective.* January 13, 2016. Further information can be found at the NREL's Life Cycle Assessment Harmonization site.

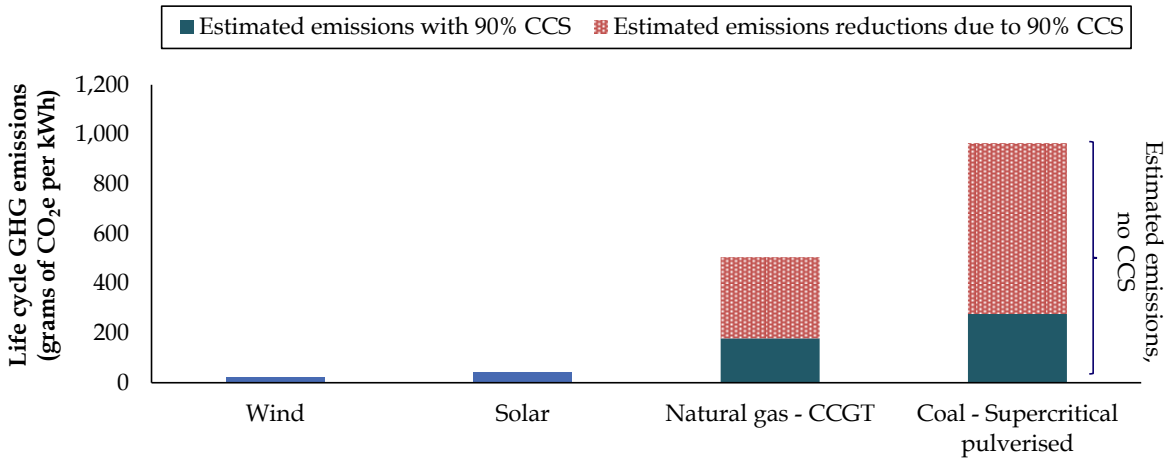
[278] NREL. *Life Cycle Greenhouse Gas Emissions from Solar Photovoltaics*. November 2012.

As is visible in the figure, renewable technologies such as wind and solar have LCA emissions levels (as measured by CO_2e per kWh) that are estimated to be much lower than fossil-fuel fired resources, such as coal and natural gas generation technologies. Based on median estimates of the LCAs, coal-fired resources emit around 20 times more CO_2e per kWh than wind and solar.[279] When comparing wind and solar, emissions levels for wind are generally estimated to be lower.

When comparing natural gas and coal, based on the estimates presented in Figure 114, natural gas is generally estimated to have lower total CO_2e emissions compared to coal-fired resources on a per-kWh basis. Median estimates for natural gas CO_2e emissions are around half those of coal, although there is some overlap between the maximum LCA estimates for combined-cycle natural gas using shale gas ("unconventional") and the minimum LCA emissions estimates for coal, attributable to the higher methane leakage rates associated with shale gas. However, based on the range of findings presented above, most studies estimate the total life cycle emissions of both conventional and unconventional combined cycle natural gas to be lower than coal.

Carbon capture and storage ("CCS") processes are one alternative to reduce the estimated life cycle emissions of fossil-fuel fired generation resources, by focusing on capturing and storing emissions during the operational stages of the generation resource's lifetime. As shown in Figure 115, gas and coal-fired generation resources with 90% CCS (i.e. captures up to 90% of emissions produced during the generation process) see significant reductions in their estimated life cycle CO_2e emissions; based on estimates from the DOE's National Energy Technology Laboratory, life cycle GHG emissions are reduced by around 65% for combined cycle natural gas generation, and around 71% for supercritical pulverized coal generation (although total estimated life cycle emissions are still significantly higher than estimates for wind and solar, which are also shown in Figure 115 for reference).

Figure 115. Estimates for life cycle GHG emissions by resource type with CCS (CO_2e per kWh)



Source: US DOE's National Energy Technology Laboratory presentation. *Life Cycle Greenhouse Gas Emissions: Natural Gas and Power Production.* June 15, 2015.

[279] NREL. *Life Cycle Greenhouse Gas Emissions from Electricity Generation*. January 2013.

However, these emissions reductions come with high costs. For example, the EIA's Annual Energy Outlook ("AEO") capital cost estimates for a new ultra-super critical coal generation facility with 90% CCS are around 64% higher than a standalone ultra-super critical coal generation facility; operating and maintenance expenses are also higher, as are the fuel requirements (more fuel is needed to generate a single net kWh of electricity).[280] Similar dynamics are also seen with natural gas-fired generation with CCS, and are a main hindrance on the more widespread usage of CCS technologies at fossil-fuel fired resources. For existing resources, the country's only operational generation facility with CCS (Petra Nova in Texas) has been idled since May, and recently issued a notification of its plan to suspend operations beginning December 20, 2020 for economic reasons.[281]

Key takeaway

Life cycle GHG emissions estimates for wind and solar resources are significantly lower than emissions estimates for fossil-fuel fired resources. Based on a review of a large number of LCA studies, median life cycle GHG emissions estimates for combined-cycle natural gas are about half those of coal (although shale gas methane leakage rates are a concern). CCS technologies can significantly reduce emissions from fossil-fuel fired electricity generation, but are presently not viewed as economic.

9.4 Coal's future

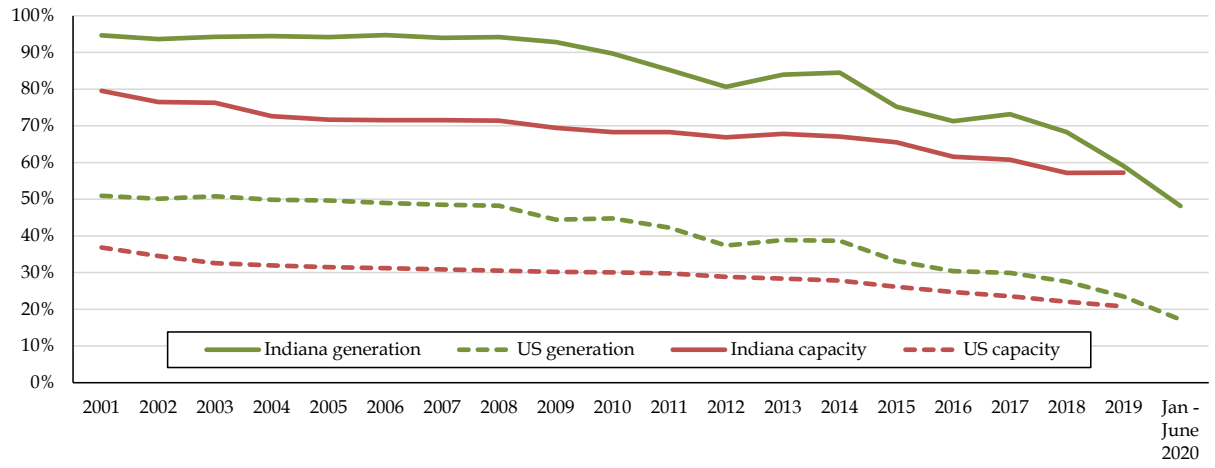
The amount of coal capacity and generation from coal-fired resources have seen significant declines over the past decade, as shown in Figure 116. Nationally, coal-fired energy, which was the largest source of electric generation in 2001 at 1,903 TWh, has declined by around 51% in 2019 to 966 TWh. Although coal remains the dominant source of both capacity and generation in Indiana, a more pronounced decline is visible for the state.

Although retirements of coal-fired facilities have been a major driver of declines in coal-fired generation, many existing resources are also seeing lower utilization rates (as evidenced by greater declines in generation versus capacity shown in Figure 116), which impacts the cost-competitiveness of coal supply. For reference, a comparison of capacity factors for relevant utility coal units in Indiana are shown in Figure 117, using annual data for 2008 and 2019. Also shown in the figure are the weighted average capacity factors for both years, which highlights the visible decline in utilization rates for the same coal facilities over the selected timeframes.

[280] EIA. *Assumptions to the Annual Energy Outlook 2020: Electricity Market Module*. January 2020.

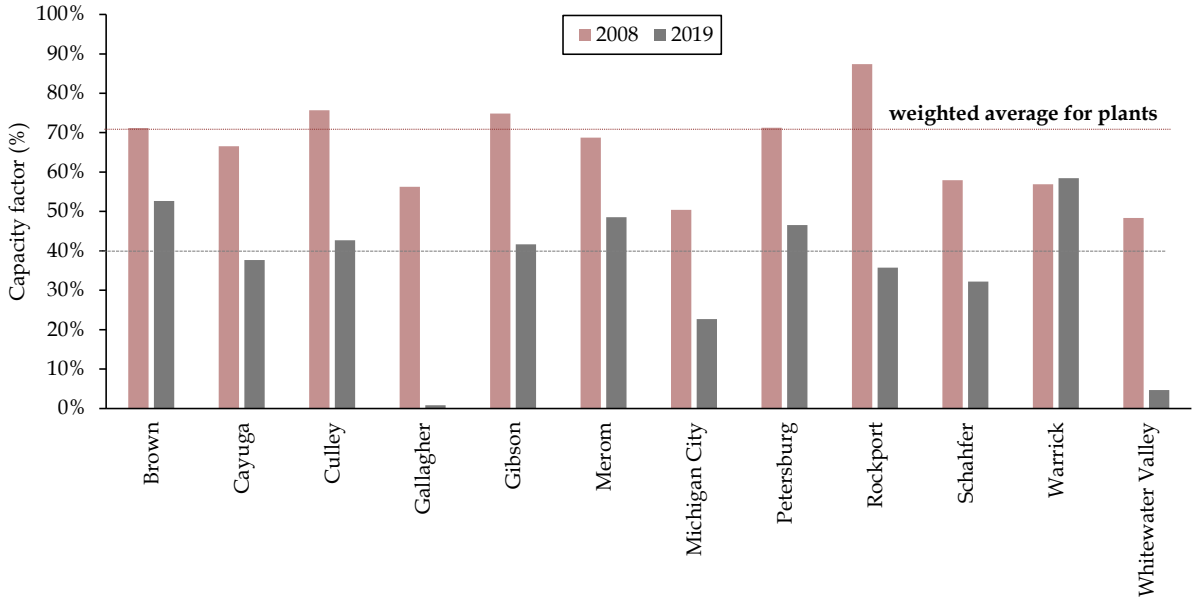
[281] Khalid, Usman. S&P Global Market Intelligence. *NRG to suspend operations at Texas carbon-capture project*. September 24, 2020.

Figure 116. Annual coal capacity and generation as a percentage of total, for Indiana and the US



Sources: EIA's electricity data browser, annual existing capacity datafile, Form EIA-860.

Figure 117. Capacity factors for relevant utility coal facilities in Indiana (2008 and 2019)



Sources: EIA forms 860 and 923 for 2008 and 2019.

Uneconomic coal dispatch in MISO

A September 2020 report published by MISO's independent market monitor, Potomac Economics, demonstrates how low natural gas prices have impacted the profitability of coal resources in the region and led to increasing instances of uneconomic dispatch of these units.

Potomac Economics' report included a review of the commitment and dispatch of coal generation in MISO over the 2016-2019 period. Given that natural gas prices had been falling in 2019, we focus on data presented for 2019. As stated by the independent market monitor itself, "[b]ecause it is not likely that the declines in natural gas prices and energy prices will be reversed in the near term, the 2019 results are the most relevant to examine for purposes of drawing conclusions and recommendations for potential changes in the upcoming years."

The report found that 17% of coal resource commitments in MISO were unprofitable in 2019 (up from 10% over the 2016-2018 period). All of these unprofitable startups were committed by vertically integrated utilities as opposed to merchant generators. In addition, the report found that 4% of all generators made inefficient and unprofitable daily decisions to keep their coal units online in 2019 (up from 3% over the 2016-2018 period). Again, these decisions were made by vertically integrated utilities. In 2019, these inefficient and unprofitable operations caused a $50 million loss (representing 5.2% of net operating revenues, up from 1.7% of net operating revenues in 2016-2018). When considering unprofitable operations only (i.e., commitment and dispatch decisions that were unprofitable but were still efficient as defined by Potomac Economics), losses grew to $178 million in 2019.

Notably, the report presents much lower cost estimates than those presented by the Union of Concerned Scientists ("UCS") and the Sierra Club in two previous reports. For example, UCS, in a May 2020 report, predicted a $350 million loss in 2018 caused by uneconomic self-commitments. In response, some utilities have sought commission approval to offer their coal plants on an economic and seasonal basis rather than on a must-run basis. For example, Xcel Energy in Minnesota projects that implementing this for its two coal plants could "save customers tens of millions of dollars and 5 million tons of carbon emissions annually by optimizing use of the plants."

Sources: Potomac Economics. *A Review of the Commitment and Dispatch of Coal Generators in MISO*. September 2020; Utility Dive. *MISO integrated utilities lost $492M from 2016-2019 via uneconomic coal dispatch: market monitor.* October 9, 2020; Union of Concerned Scientists. *Used, But How Useful? How Electric Utilities Exploit Loopholes, Forcing Customers to Bail Out Uneconomic Coal-fired Power Plants*. May 2020; Sierra Club. *Playing with Other People's Money: How Non-economic Coal Operations Distort Energy Markets*. October 2019; Utility Dive. *Xcel Minnesota: Running coal seasonally will save customers millions, reduce emissions.* January 8, 2020.

A number of factors have influenced the retirement of coal facilities and impacted the competitiveness of existing coal-fired generation, including:[282]

[282] Vectren. *2019/2020 Integrated Resource Plan*. June 2020.

- declining costs associated with energy supplied from gas-fired and new renewable resources, as well as the increased penetration and availability of these resources;
- changing system requirements, as increasing penetration of intermittent resources has required other supply resources to have greater levels of flexibility;
- aging infrastructure (with new-build of coal generation not considered economic or prudent given the dynamic changes that are under way on the supply and demand side);
- environmental regulations, and the costs associated with upgrades necessary to achieve compliance with these regulations (larger impact on older and less efficient coal facilities); and
- other environmental considerations, including public and investor pressure to reduce emissions.

These factors are expected to continue going forward, with economic, environmental, and age-based considerations negatively impacting the outlook for coal in the longer term. Figure 118 presents an outlook for the annual installed capacity of relevant utility coal facilities in Indiana between 2021 and 2038, based on the planned, projected, or preferred coal retirement schedules presented in Figure 119. This information, which is based on content in utility IRPs, suggests around 11.2 GW of coal capacity may be retired by 2038, with about half of these retirements taking place by 2026. For reference, the annual capacity-weighted age of this coal fleet is presented in Figure 120 for the 2021 to 2038 timeframe (with retirements based on the schedules in Figure 119).

Figure 118. Potential annual installed capacity for relevant utility coal facilities in Indiana (2020 – 2038)

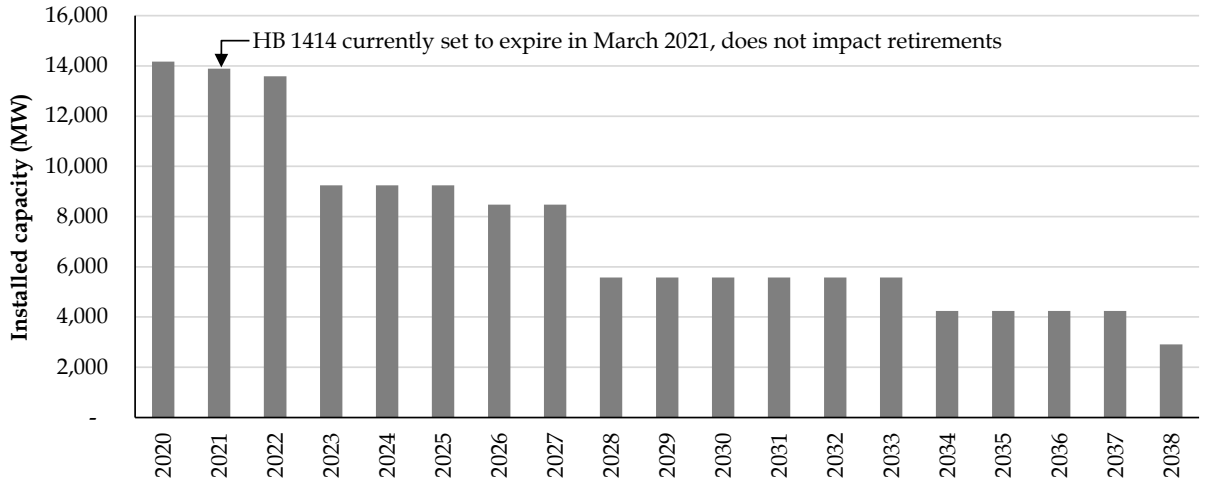
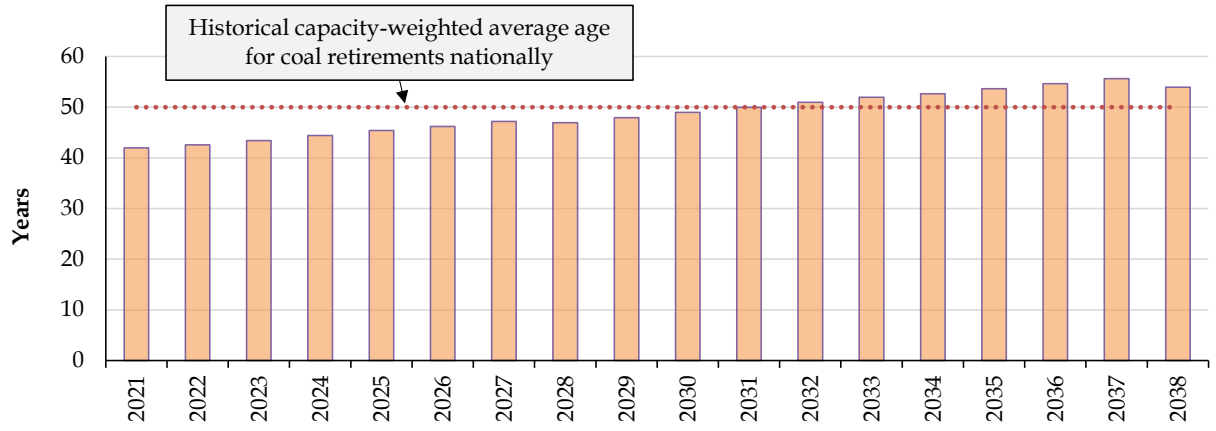


Figure 119. Indiana's coal unit capacities, online and potential retirement years, and ages at retirement

Unit	Owner	Nameplate capacity (MW)	Online year	Retirement year	Retirement age
Petersburg 1	IPL	282	1967	2021	54
Gallagher 2	Duke	150	1958	2022	64
Gallagher 4	Duke	150	1961	2022	61
Brown 1	Vectren	265	1979	2023	44
Brown 2	Vectren	265	1986	2023	37
Culley 2	Vectren	104	1966	2023	57
Merom 1	Hoosier Energy	540	1983	2023	40
Merom 2	Hoosier Energy	540	1982	2023	41
Petersburg 2	IPL	523	1969	2023	54
Schahfer 14	NIPSCO	540	1976	2023	47
Schahfer 15	NIPSCO	556	1979	2023	44
Schahfer 17	NIPSCO	424	1983	2023	40
Schahfer 18	NIPSCO	424	1986	2023	37
Warrick 4	Vectren (50%)	162	1970	2023	53
Gibson 4	Duke	668	1979	2026	47
Whitewater Valley 1	IMPA	35	1955	2026	71
Whitewater Valley 2	IMPA	65	1973	2026	53
Cayuga 1	Duke	531	1970	2028	58
Cayuga 2	Duke	531	1972	2028	56
Michigan City 12	NIPSCO	540	1974	2028	54
Rockport 1	I&M	1300	1984	2028	44
Gibson 3	Duke	668	1978	2034	56
Gibson 5	Duke	668	1982	2034	52
Gibson 1	Duke	668	1976	2038	62
Gibson 2	Duke	668	1975	2038	63

Culley 3	Vectren	265	1973
Petersburg 4	IPL	671	1986
Petersburg 3	IPL	671	1977
Rockport 2	I&M	1300	1989

Figure 120. Capacity-weighted age of remaining coal units in Indiana with retirements



Note: Age is based on online and potential retirement years

Sources: Based on information contained in utility IRPs, the IURC's 2020 Report to the 21st Century Energy Policy Development Task Force, and third-party commercial databases.

The above timelines do not represent a commitment on behalf of the utilities to these retirement schedules, but do provide an indication of their general thinking around the competitiveness of coal in the longer term in light of the considerations mentioned previously. Similarly, for the remaining coal units that do not have a stated retirement year, this does not represent a commitment to keep the units online in the longer term (for example, I&M's Rockport Unit 2 lease expires in 2022). Decisions around resource retirements will be re-evaluated, as more clarity may arise in subsequent IRP updates on whether the costs of continuing coal operations can be done economically (as more coal units retire, those that remain may be able to produce at utilization levels high enough to continue operations economically). Age-based considerations will also continue to play a role in the longer term.

Acceleration of the retirement timelines are also possible based on economic and environmental considerations. The cost of procuring replacement energy and capacity must be taken into account, though these costs may be offset by the decrease in operating and maintenance costs associated with the retired asset. Cost-benefit analysis needs to be performed holistically, incorporating all cost impacts for ratepayers. Factors related to more stringent environmental rules, potential coal phase-outs, and carbon pricing policies would put significant pressure on coal-fired resources and accelerate retirement schedules. Policy and legislative action may succeed in slowing the pace of coal retirements, but a combination of the aforementioned factors will lead to continued declines in coal.

Key takeaway

Coal generation and capacity have consistently declined over the past decade. The economic and environmental factors that have impacted coal-fired resources historically are expected to continue going forward. Large amounts of coal capacity retirements are expected over the next decade. Further pressure would emerge if more stringent environmental rules or carbon pricing policies were to be implemented. Securitization as a possible approach to addressing the stranded cost issues that arise from the early retirement of coal units are covered in 10.2.3.

9.5 Renewable energy siting

Renewable energy siting issues have arisen as many states, including Indiana, see increasing penetration of wind and solar resources. Considerations that emerge when dealing with renewable energy siting, most commonly with larger-scale wind projects can include the impact on wildlife (such as impacts on bird and bat species that live in, around, or migrate through potential wind farm development areas); the potential for wind turbines to interfere with radar signals; and concerns raised by local stakeholders or communities situated around the proposed renewable development.[283]

Concerns raised by local stakeholders or communities situated near proposed developments can be directed towards any new development, including solar, as well as transmission infrastructure required to move the power generated by new renewable projects. However, large-scale wind

[283] NREL. *An Initial Evaluation of Siting Considerations on Current and Future Wind Deployment*. July 2016.

projects tend to cause more concerns. Individuals and communities located near wind farms can express complaints or concerns related to:

- the sounds and vibrations produced by wind turbines;
- visual impairments of wind farms (as they stand out visually, along with some concerns around shadow flicker that can be produced by wind turbines); and
- the potential impact on property values.[284]

These concerns can lead to community opposition to wind farm development at the local level.

According to a survey carried out by LBNL, around 57% of respondents living within five miles of a wind project had positive or very positive attitudes towards them, while 8% viewed them negatively or very negatively; for those located within under half a mile, 52% viewed them positively to very positively, but the number of respondents who viewed them negatively to very negatively rose to 25% (with the remainder being neutral).[285] Given the land requirements associated with wind farms (i.e., they require more total land, but as individual turbines are spaced out land sharing is possible), local support for wind farms can emerge for a number of reasons, including additional revenue streams for landowners. Local opposition, however, is still a real issue that needs to be addressed in the planning for new-build of renewable resources, especially as renewable resource penetration grows.

Concerns by local communities and individuals can be addressed through a more open development process, as "projects that begin in secret and developers that are seen as aggressive or misleading toward landowners and community members foster opposition and mistrust."[286] Gaining local support through public consultations significantly reduces the threats facing potential new-build renewable resource development. Lack of local support can lead to significant hurdles, including the potential for the project to be halted. Proper renewable energy siting should, therefore, adequately consider issues raised by stakeholders and attempt to mitigate local opposition, which is more likely to emerge if the local community does not perceive the development as being beneficial.

Renewable energy siting authority

Renewable energy siting authority can rest at the state or local level. The benefits of state-level authority include that it provides more consistent and standard processes and reduces the potential for development hurdles. The benefit of local-level authority is that it may more adequately consider unique circumstances or concerns of residents. Hybrid approaches are also possible, and in practice hybrid approaches or local-level authority have been much more common than state-level authority in the US.[287]

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[284] Union of Concerned Scientists. *Environmental Impacts of Wind Power*. Published March 5, 2013.

[285] Hoen et al. *National Survey of Attitudes of Wind Power Project Neighbors: Summary of Results*. January 2018.

[286] Gross, Samantha. *Renewables, Land Use, and Local Opposition in the United States*. January 2020.

[287] Jesse Heibel and Jocelyn Durkay. (November 2016). State Legislative Approaches to Wind Energy Facility Siting. Accessed August 14, 2020.

In Indiana, renewable energy siting is currently regulated at the local level. A number of counties have zoning ordinances related to wind energy siting regulation, with some ordinances placing restrictions on the development of large wind projects through height limit and siting regulations.

Local opposition is an ongoing concern for wind development in Indiana. In one recent example, in 2019, the planned 300 MW Roaming Bison Wind project in Montgomery County ran into local resident opposition that stalled the project and led to more stringent county zoning rules for wind development.[288] As a result of the opposition and resulting rule changes, the proposed project has been changed, with the developer evaluating whether it is feasible to continue with the project.[289]

The renewable energy siting issue has led to debates on the degree of local authority and its impact on wind project development. Some renewables advocates have argued that some local wind ordinances are stunting development and impacting investor confidence.[290] On the other hand, local resident opposition groups are strongly in favor of allowing local authorities to set rules around wind development. This suggests that renewable energy siting considerations will continue to be a major issue for project development going forward. In the meantime, the Environmental Resilience Institute ("ERI"), a department of Indiana University, and the Great Plains Institute ("GPI") are developing an Indiana-specific renewable energy siting guide designed to aid county governments in decisions regarding large-scale solar and wind installations.[291] The siting guide is expected to be released in Fall 2020.

Key takeaway

Renewable energy siting considerations are one potential hurdle (but not the only hurdle) for Indiana developing its theoretical wind potential (covered in Section 4.5.1). Debates around renewable energy siting have already emerged as a contentious issue in Indiana, with local zoning ordinances impacting some proposed project developments. State-level guidelines can aid local authorities in their consideration of renewable energy siting rules. However, state mandates can provoke a backlash that further slows development.

9.6 Energy efficiency

Energy efficiency ("EE") in the electricity context refers to programs that target reducing the energy consumed by end-use products, ideally without affecting their functionality.[292] A simple example of an energy-efficient process is switching from incandescent lighting to LED lighting, which requires less energy but still provides the same functionality. Decisions around switching to more energy-efficient processes can be made at the individual level (reducing energy

[288] Miley, Scott. Indiana Economic Digest. *Two-year panel to guide Indiana energy policy: Task force targeting local conflicts with wind and other renewable energy projects*. December 15, 2019.

[289] Roaming Bison Wind website. About Roaming Bison. Last accessed September 14, 2020.

[290] Miley, Scott. Indiana Economic Digest. *Two-year panel to guide Indiana energy policy: Task force targeting local conflicts with wind and other renewable energy projects*. December 15, 2019.

[291] Indiana University's Environmental Resilience Institute. *Large-scale solar and wind siting resources for local governments*. Accessed August 14, 2020.

[292] US EIA glossary of terms.

consumption can lead to lower electricity bills), although promotion and incentivization can have a large impact on overall adoption. Promotion and incentivization of energy efficiency programs and policies can be provided by a number of parties, including utilities, municipalities, and states. Through well-designed and targeted energy efficiency programs and policies, the costs associated with energy efficiency incentivization can be lower than the benefits associated with the reduction in energy consumption, leading to a net benefit. The reduction in energy consumption through energy efficiency programs can also defer or reduce the need for new-build electricity generation, transmission, and distribution infrastructure. For these reasons, energy efficiency is often considered a useful resource in technology-neutral least-cost system planning.

Energy efficiency policies can be broad in focus, or designed specifically to target selected aspects of residential, industrial, or commercial customers. Examples of energy efficiency measures in Indiana include:

- **Energy Star:** Energy Star rebates are offered through a Federal tax credit program. These rebates are available for qualified energy efficient appliances for residential customers, builders of energy efficient homes, and energy efficient commercial buildings.[293] The rebate program has been extended retroactively through December 31st, 2020;
- **building codes:** the Indiana Energy Conservation Code is a mandatory, statewide, and state-developed code that applies to both residential and commercial buildings. Residential construction must comply with the 2009 Indiana Residential Code ("IRC"). Commercial buildings must meet the American Society of Heating, Refrigerating and Air-Conditioning Engineers ("ASHARE") 90.1-2007 standards. The State has completed limited activities to ensure code compliance, including training and outreach;[294]
- **residential:** residential customers may use home energy audits, including the Energy Star Home Energy Yardstick and the Home Energy Rating Systems ("HERS") Index. The State government also encourages the use of Energy Star appliances. A variety of utility energy efficiency programs target residential customers, including (but not limited to): Residential Lighting Programs; Residential Heating, Ventilation and Air Conditioning ("HVAC") Energy Efficient Rebates Programs; and Residential Appliance Recycling Programs;[295] and
- **commercial and industrial ("C&I")**: energy audits and efficiency training can be performed by utilities or other parties. A variety of utility energy efficiency programs target commercial and industrial customers, including (but not limited to): the C&I Perspective Program; the C&I New Construction Program; and the Small Business Direct

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[293] Energy Star. (n.d.). *Federal Income Tax Credits and Other Incentives for Energy Efficiency*. Retrieved from Energy Star: https://www.energystar.gov/about/federal_tax_credits

[294] American Council for an Energy-Efficient Economy. (2019, 10). State and Local Policy Database. Retrieved from American Council for an Energy-Efficient Economy: https://database.aceee.org/state/indiana

[295] Vectren. *2019/2020 Integrated Resource Plan*. June 2020; Northern Indiana Public Service Company LLC. *2018 Integrated Resource Plan*. October 31, 2018.

Install Program.[296] Although C&I customers account for the majority of Indiana's energy use, C&I customers with a peak load greater than 1 MW can opt out of all utility-funded energy efficiency programs (and their associated fees).

As discussed in Section 5.3.2, with the rollback of the State's energy efficiency standard in 2014, utilities in Indiana now design their own energy efficiency targets and programs, which must be submitted to the IURC for approval. According to EIA data for 2018, utilities in Indiana reported energy savings of around 800 GWh, with Indiana ranking 13th nationally in terms of total energy savings, and 19th nationally based on the ratio of total energy savings to total energy sales (0.77%).[297]

Further expansion to energy efficiency levels are possible, although actual levels will depend on economics and the amount of participation by customers. In this regard, information contained in IPL's 2019 IRP provides useful information related to the energy efficiency potential going forward in its service territory, broken down into:[298]

- **technical potential:** the theoretical upper limit for energy efficiency savings, assuming no barriers to customer adoption (such as financial barriers, customer awareness, and willingness to participate);
- **economic potential:** a subset of the technical potential that includes only those measures that are deemed to be cost-effective based on a measure-level screening using the Utility Cost Test;
- **Maximum Achievable Potential ("MAP"):** the potential for energy efficiency, with the assumption that an incentive equal to 100% of the energy efficiency measure's incremental cost is paid, and with limited barriers to participation; and
- **Realistic Achievable Potential ("RAP")**: the potential for energy efficiency, with the assumption that incentives paid and barriers to participation are aligned with historical levels, and with no constraint placed on spending.

Figure 121 presents the **cumulative** energy savings estimated through the analysis contained in IPL's IRP over a 19-year period from 2021 to 2039, for each of the groupings described in the bullet points above, and broken down by customer class (residential, commercial, industrial). As noted previously, the technical and economic potentials are meant to represent upper limits for energy efficiency levels, although they are not viewed as representing realistic targets, with the MAP and RAP potential estimates developed to define attainable targets.[299] As is visible through the difference in energy efficiency levels between the MAP and the RAP, expansion of energy efficiency is directly linked to the incentivization of and willingness to grow energy efficiency

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[296] Ibid.

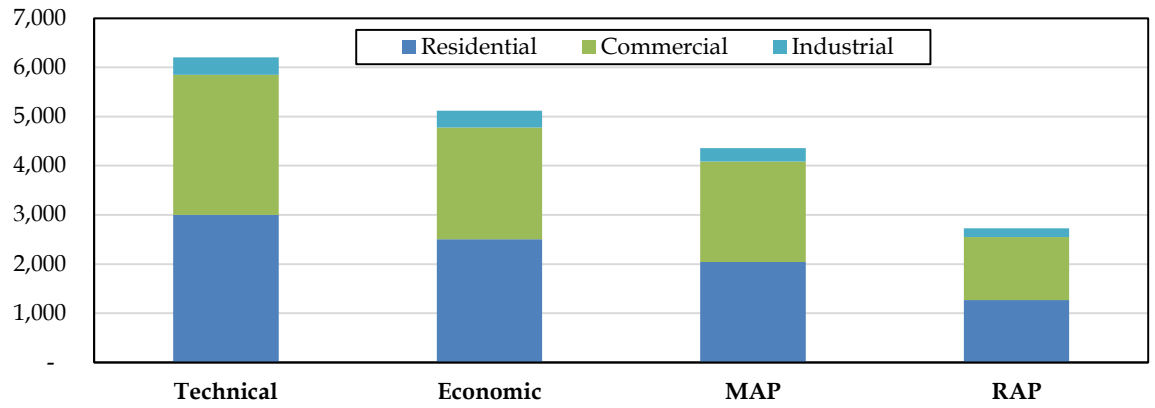
[297] EIA Form EIA-861 data.

[298] Indianapolis Power & Light Company. *2019 Integrated Resource Plan, Volume 1 of 3.* December 16, 2019.

[299] *Ibid*.

programs, with policymakers playing an important role. Although the information presented below is specific to IPL, this relationship applies statewide.

Figure 121. Cumulative IPL EE potential for 2021-2039 (GWh)



Note: These cumulative values represent around 2.2%, 1.8%, 1.5%, and 1% respectively of IPL's total annual energy forecast over the 2021 to 2039 timeframe.

Sources: IPL's 2019 IRP Volume 1 of 3.

Key takeaway

Energy efficiency can be a useful resource in technology-neutral, least-cost system planning, and can defer or reduce the need for new-build electricity generation, transmission, and distribution infrastructure. EE measures should therefore form an important resource in utility integrated resource plans, but selection of EE measures based on economics will only make sense for those that are less expensive than conventional generation alternatives. Further expansion to energy efficiency levels are possible in Indiana, although actual levels will depend on economics and barriers to participation.

9.7 Uncertainty around COVID's impact on load and utilities

The COVID-19 ("COVID") pandemic has impacted individuals and businesses in all sectors across the nation, including Indiana, and created significant levels of uncertainties. Two specific areas are explored below: the implications of the pandemic on load, and short-term considerations that regulators have grappled with that are directly linked to COVID.

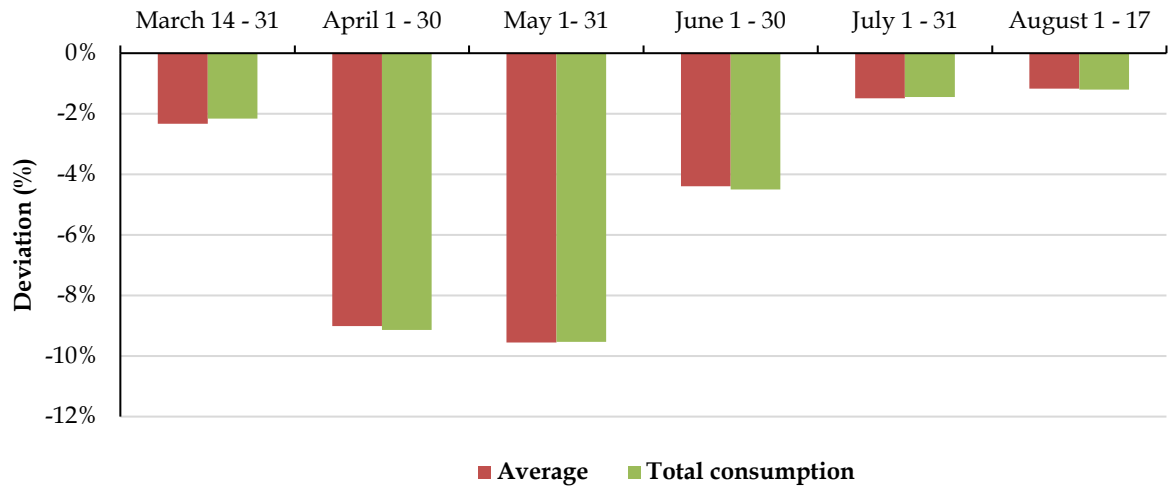
9.7.1 Impact on load

During the initial stages of the pandemic, a combination of lockdown measures, reductions to commercial and industrial consumption, and increasing numbers of residential consumers staying home led to a noticeable impact on peak demand, total consumption, and the overall load shape. This can be seen in the figures below, which present monthly data from MISO on simulated and actual energy usage from March 14th up to August 17th, 2020. The simulated data is based on a MISO backcast model using actual weather (to remove weather bias); a comparison

of simulated data against actual data provides an estimate for the "load deviation" that can be attributable to the effects of COVID-19 related closures and stay-at-home ordinances on load.[300]

First, Figure 122 presents the deviation between simulated and actuals for total energy and average load in MISO. As is visible in the figure, there was a significant drop in total energy usage in April and May (around 9% and 10%, respectively) when comparing the actuals to simulated estimates. As states started to reduce restrictions and lift lockdown measures, load, in turn, saw some recovery, with July and August periods seeing estimated load deviations of around -1.2% and -1.4%. These deviations are still below estimates for load if not for the pandemic, but indicate a rapid recovery from the worst stages.

Figure 122. Monthly deviation of actual versus simulated total and average energy consumption in MISO



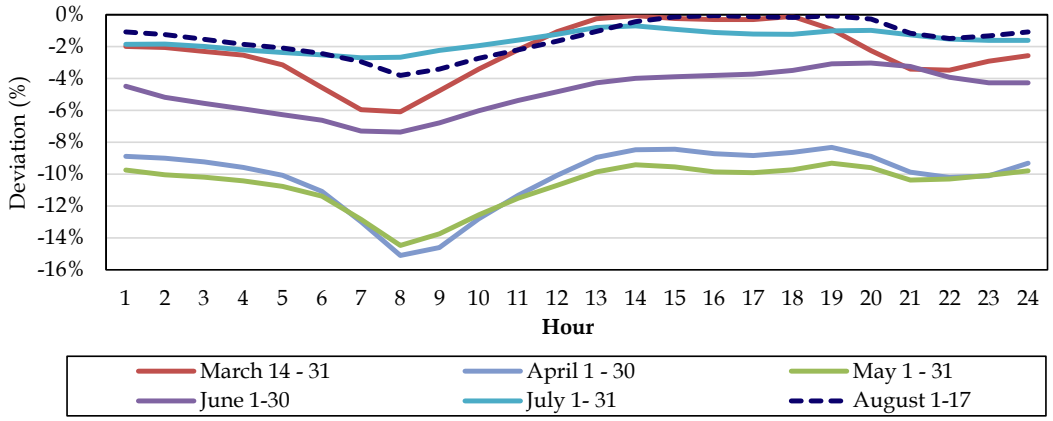
Note: Deviation represents percentage difference from the actual over simulated data

Source: MISO Presentation. *COVID-19 Impact to Load & Outage Coordination*. August 17, 2020.

Next, Figure 123 presents the average hourly deviations estimated by MISO using the same data for the past six months. As is visible in the figure, a large drop in average April and May hourly loads (when comparing the actual to simulated) was then followed by a quick recovery in July and August, although load in most hours is still below estimates for load if not for the pandemic. The load deviations are not consistent across all hours, implying a change to the average hourly consumption patterns. This was most visible in the morning hours around 8 am, most likely attributable to shifting routines (e.g., more residential consumers are starting their days later).

[300] MISO Presentation. *COVID-19 Impact to Load & Outage Coordination*. August 17, 2020.

Figure 123. Average hourly deviations of actual versus simulated load in MISO, by month



Source: MISO Presentation. *COVID-19 Impact to Load & Outage Coordination*. August 17, 2020.

In the short term, there is a significant amount of uncertainty around the direction of load changes that can be attributable to COVID. For example, it is possible that similar lockdown measures as a result of a second wave will lead to large declines in energy usage, in which case the drops seen in April and May can serve as an indication of what a known worst-case scenario could look like. In the medium- to longer-term, there is also significant uncertainty around the permanence of the demand destruction and load pattern changes that have emerged as a result of the pandemic. Aside from the direct economic impacts, examples of potential changes include that: increasing numbers of individuals may continue to work from home; commercial load may continue to be impacted by reduced in-person foot traffic; and industrial processes may accelerate changes related to automation. In contrast, one potential demand upside driver that has been discussed relates to the re-shoring of industrial supply chains for products that are deemed as essential for national security purposes (e.g., medical devices and equipment, pharmaceutical products).[301]

9.7.2 Impact on ratepayers and utilities

Given the significant economic impact that was seen by residential, commercial, and industrial customers, one of the first major focuses of regulators and policymakers during the initial stages of the pandemic was measures to ensure customers continued to have access to utility services. In Indiana, this was first done through Executive Order 20-05, which declared electric and gas utilities to be an essential service and prohibited utilities from discontinuing service to any customer.[302] The disconnection moratorium expired after August 14th, 2020, although the IURC required utilities under its jurisdiction to offer payment arrangements and waive certain fees until October 12th, 2020.[303]

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[301] See for example: Indiana University Public Policy Institute. *Economic, Fiscal, and Social Impacts of the Transition of Electricity Generation Resources in Indiana*. August 2020.

[302] State of Indiana Executive Department. *Executive Order 20-05*. Signed March 19, 2020.

[303] Indiana OUCC. COVID-19 Investigation. Last modified August 28, 2020.

Considerations around the financial impact on utilities have also arisen, driven by a combination of the short-term load reductions discussed previously, the increase in the numbers of customers that were facing an inability to pay their utility bills, and COVID-related operating and maintenance expenses that were incurred by utilities (e.g., to enhance their safety measures while maintaining operations as an essential service). These three issues are being considered through the IURC's ongoing consolidated Cause No. 45380. Through the Phase 1 Order of the investigation, the IURC has:

1) **denied** utility requests for cost recovery of lost revenue related to customer load reductions;
2) **authorized** utilities to defer COVID-related impacts linked to prohibition measures (such as prohibitions on utility disconnections, and prohibitions on the collection of certain utility fees) as well as other items such as bad debt expenses, which, if determined to be reasonable and necessary, are entitled to future recovery in rates; and
3) **deferred** to Phase 2 of the investigation any decision on utility requests related to increased COVID-linked operations and maintenance and pension expenses.[304]

These issues generally relate to selected immediate and short-term impacts of COVID on ratepayers and utilities, although the impact going forward in the short, medium, and longer term could be much broader. This presents significantly more uncertainty and makes system planning extremely difficult. On the supply side, planning for and construction of new-build resources, as well as planning around retirements of existing resources, may be impacted in some form – although decisions are difficult to make until uncertainty levels decline. On the demand side, in the event that demand destruction lasts beyond the short term, customers could see increases in their electricity rates as fixed system costs are spread over lower consumption levels.

> "It is generally undisputed that the COVID-19 pandemic is an unprecedented and extraordinary event. However, because the event is still occurring and the timeframe for its end uncertain, we cannot begin to understand the gravity or longer-term financial impact the event will have on utilities and their customers."
>
> IURC. *Phase 1 and Interim Emergency Order of The Commission [Cause No. 45380].* Approved June 29th, 2020.

Key takeaway

There is a significant amount of uncertainty around the implications of the COVID pandemic on load, the permanence of demand destruction, the planning around supply-side resources (both new and existing), and the implications of all these factors on ratepayers. The IURC's responses are typical of most state regulators.

[304] IURC. *Phase 1 and Interim Emergency Order of The Commission [Cause No. 45380].* Approved June 29, 2020.

10 What can be done through the legislative process?

The following chapter begins with a brief review of the extent of past legislative involvement in the energy sector in Indiana and its neighboring states. We then examine trends in the legislative efforts that have been pursued across the US to impact electricity rates for consumers. These efforts have generally been focused on the following:

1. pursuing clean energy;
2. enhancing market access for generators and customers;
3. considering the treatment of legacy assets; and
4. implementing alternative ratemaking regimes.

The survey of legislative efforts highlights key considerations in deciding what can be done through the legislative process. It is important to bear in mind the role of legislation versus regulation. Generally, laws are enacted by the legislature and provide the authority for certain bodies to write regulation, whereas regulations "explain the technical, operational, and legal details necessary to implement laws."[305] Stated another way, legislation seeks to point an industry in a certain direction, while regulation provides the map to get there. In this sense, legislation should avoid being too prescriptive, and should instead delegate responsibility for enforcement to regulatory bodies wherever possible. This is especially true given that it is much harder to change legislation once it is codified than it is to change regulation.

10.1 Legislative involvement in the energy sector

We begin this chapter by taking stock of the legislative framework that exists in Indiana and its neighboring states. Legislative involvement in the energy sector is largely limited to the following: providing guidance on the general direction of the sector through the setting of energy goals/standards or issuing a state energy plan, establishing state agencies to regulate the industry, as well as determining the authority delegated to these agencies. The following subsections address each of these actions.

10.1.1 Determining state energy goals

Legislation is an effective tool to drive change in the energy sector, where policy goals can be articulated through mechanisms such as a renewable portfolio standard ("RPS") or a statewide energy plan.

An RPS is one of the most common ways states choose to set their renewable energy and decarbonization goals. An RPS sets a specific target for the level of renewable generation a state wants to procure by a given year, and utilities become bound by law to meet it. The targets can be met by building more renewable generation, importing renewable energy from other regions,

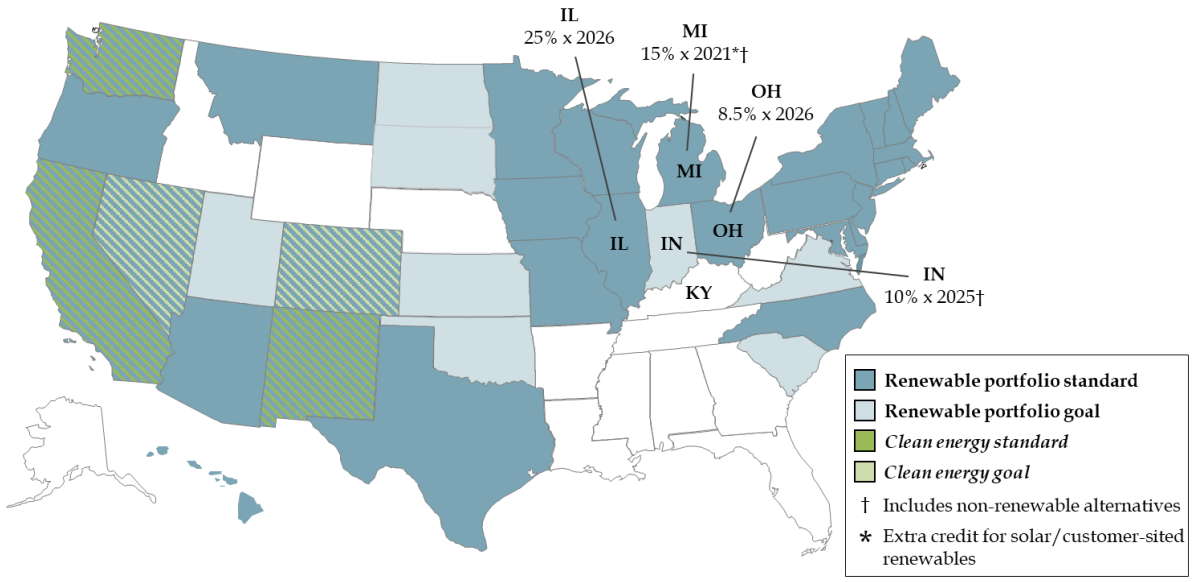
[305] US EPA. *Laws & Regulations.* <https://www.epa.gov/laws-regulations>

or by purchasing renewable energy credits ("RECs"). Some jurisdictions may choose to enact a clean energy standard ("CES") instead, which also includes technologies such as nuclear.

As discussed in Section 5.3.1, Indiana promulgated its voluntary clean energy standard in 2011 through Senate Bill 251. Titled the CHOICE program, Indiana set a voluntary threshold for utilities of procuring 10% of electricity from clean energy sources by 2025, relative to 2010 retail sales.[306] Although no utilities have sought to participate in the program to date, Indiana is on track to meet its voluntary commitment due to an influx of wind generation in the last decade. As of 2019, Indiana generated 6% of 2010 electricity sales from renewables (wind, solar, hydro).

Among its neighboring states, Indiana has one of the softer renewable targets, with the exception of Kentucky, where there has been no legislatively mandated energy goal. In contrast, Michigan, Ohio, and Illinois each have mandatory RPS' of 15% by 2021, 8.5% by 2026, and 25% by 2026, respectively. A summary of these standards is illustrated in Figure 124.

Figure 124. Renewable and clean energy standards across the US



Source: DSIRE. *Renewable & Clean Energy Standards*. September 2020.

Another way that states establish their energy goals is through the development of a state energy plan. According to the National Association of State Energy Officials ("NASEO"), "[s]tate energy plans enable states to capitalize on existing energy resources, infrastructure, and human capital through targeted goals and directives to encourage economic development and … set forward-thinking energy policies for the state. … [A] state energy plan is a package of strategic goals with recommended policy and program actions to support those goals."[307]

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[306] DSIRE. Clean Energy Portfolio Standard. Last updated June 18, 2018.

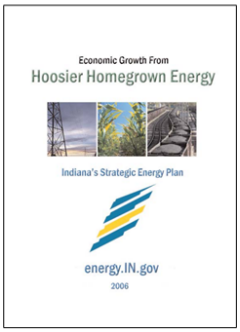
[307] National Association of State Energy Officials. *NASEO's State Energy Planning Guidelines*. 2018.

Figure 125 illustrates the key features of the state energy plans previously published in Indiana and its neighboring states. Notably, and as mentioned in Section 5.3, Indiana has not had a state energy plan since the adoption of the 2006 Strategic Energy Plan by then Governor Mitchell Daniels, which aimed "to create a strategy to grow Indiana's economy by producing more of its energy from its own natural resources, while encouraging conservation and energy efficiency."[308]

In terms of Indiana's neighboring states, Kentucky's state energy plan is equally dated, having been adopted by then Governor Steven Beshear in 2008.[309] Illinois has yet to develop a state energy plan; efforts were initiated in 2016 to develop an Illinois Energy Roadmap, but no such document was ever published.[310] Ohio and Michigan have both released more recent state energy plans (2014 and 2016, respectively), although it is unclear if these plans are still active as they were adopted under previous administrations.

Figure 125. Summary of previous state energy plans in Indiana and neighboring states

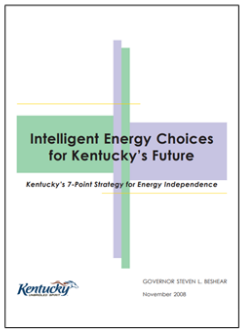
Indiana



Indiana's Strategic Energy Plan, Indiana Office of Energy Development (2006)

Topics covered:
- Energy independence
- Conservation and energy efficiency
- Clean coal
- Bioenergy

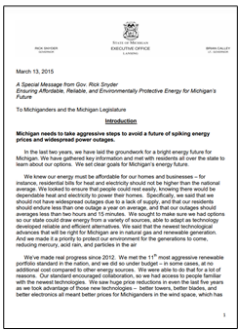
Kentucky



Intelligent Energy Choices for Kentucky's Future, Governor's Office (2008)

Topics covered:
- Renewable and Efficiency Portfolio Standard (REPS)
- Energy efficiency
- Biofuels, coal-to-liquids, and coal-to-gas technologies

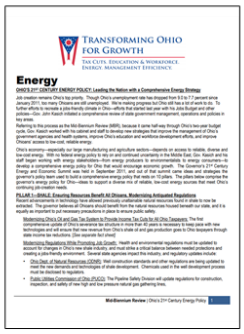
Michigan



Ensuring Affordable, Reliable, and Environmentally Protective Energy for Michigan's Future, Michigan Agency for Energy (2016)

Topics covered:
- Affordability
- Adaptability
- Reliability

Ohio



Ohio's 21st Century Energy Policy: Leading the Nation with a Comprehensive Energy Strategy, Governor John Kasich (2014)

Topics covered:
- Balanced energy portfolio
- Workforce training
- Energy efficiency

Source: NASEO. *Statewide Comprehensive Energy Plans.* <https://naseo.org/stateenergyplans>

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[308] IURC – Loraine L. Seyfried. *Indiana's Strategic Energy Plan.* 2006.

[309] Governor Steven L. Beshear. *Intelligent Energy Choices for Kentucky's Future: Kentucky's 7-Point Strategy for Energy Independence.* November 2008.

[310] Illinois Department of Commerce & Economic Opportunity. *Illinois Energy Roadmap Project*.

LEI understands that it is Indiana's intention to develop a new statewide energy policy. As part of this effort, the Indiana legislature established the 21st Century Development Task Force in 2019 to inform this process.[311] Under House Bill 1278, the 15-member Task Force is required to examine the following issues, and develop recommendations in a report to the General Assembly and Governor, among others, to be issued by the end of the year:

- examine the state's existing policies regulating electric generation portfolios;
- examine how possible shifts in electric generation portfolios may impact the reliability, system resilience, and affordability of electric utility service; and
- evaluate whether state regulators have the appropriate authority and statutory flexibility to consider the statewide impact of the changes described above, while still protecting ratepayer interests.[312]

As Indiana pursues the development of a refreshed energy policy, it will be important for policymakers to consider the four key characteristics of a valuable state energy plan: it should be comprehensive, adaptable, guiding, and strategic. The textbox describes each of these features in detail.

Key elements of a state energy plan

- ***Comprehensive***: takes into consideration a holistic perspective of the state's energy profile, including all energy resources and end-use sectors, as well as input from key public and private stakeholders;
- ***Adaptable***: projects future energy supply and demand and models the potential impacts of supply shifts, geopolitical risks and uncertainties, technological change, and other factors that affect short- and long-term energy needs;
- ***Guiding***: provides a framework that allows state and business decision makers to make informed and educated judgments based on the predictability ensured by a defined and structured plan; and
- ***Strategic***: offers a deliberate and vetted plan of action that lays out clear recommendations and actions that are set within measurable and achievable goals.

Source: NASEO. *State Energy Planning Guidelines*. 2018.

The development of a state energy plan should follow a well-designed process. The first step is to have the state energy plan initiated by a top-level state authority, which would guarantee that the required resources are allocated to its development and ensure that the resulting plan is seriously considered for implementation. The development of a state energy plan also requires

[311] Indiana General Assembly. *House Bill 1278*. <http://iga.in.gov/legislative/2019/bills/house/1278>

[312] 21st Century Energy Policy Development Task Force. *Information Report*. October 31, 2019.

data collection and public input. After developing the goals and specific actions required to reach them, the energy plan should be publicized, implemented, and the progress should be monitored.

10.1.2 Review of legislative actions in Indiana and neighboring states

Following a review of the degree of legislative involvement in the energy sector as compared to its neighboring states, it is clear that Indiana does not have any unusual or onerous legal requirements.[313] Essentially, and in line with its neighboring states, Indiana's legislature provides the mandate for the main regulatory body (i.e., the IURC), and is used as a policymaking tool, whereby actions such as renewable policies are enacted in the form of statutes. Figure 126 summarizes the legislative efforts that have been pursued in Indiana and its neighboring states.

Figure 126. Degree of legislative involvement in energy sector in Indiana and neighboring states

State	Public Service Commission?	State Energy Office?	Separate Department of Environmental Protection?	Renewable Portfolio Standard?	State Energy Plan?
Indiana	Yes	Yes	Yes	Somewhat – see notes below	Somewhat – see notes below
Illinois	Yes	Yes	No	Yes	No
Kentucky	Yes	Yes	No	No	Somewhat – see notes below
Michigan	Yes	Yes	No	Yes	Somewhat – see notes below
Ohio	Yes	Yes	Yes	Yes	Somewhat – see notes below

Yes | Somewhat – see notes below | No

Notes: In the case of Renewable Portfolio Standards, Indiana has a voluntary goal, whereas Illinois, Michigan, and Ohio each have mandatory targets. As for state energy plans, Indiana, Kentucky, Michigan, and Ohio each published one at some point, although none seem to be active today.

Overall, all the states reviewed have similar bicameral legislatures tasked with lawmaking for their energy sectors. Legislatures across all five states have each established a public service commission, a state energy office, and a department focused on environmental protection for oversight and enforcement (although in the case of Illinois, Kentucky, and Michigan, these latter two agencies are housed under the same department).[314] The mandates for these regulatory bodies have also been determined through legislation and are consistent across all states reviewed. This suggests that these entities are likely sufficient for the effective monitoring and

[313] LEI defines "onerous" as a task that incurs a significantly greater legal burden than would be expected or observed elsewhere.

[314] For Illinois, this is the Illinois Environmental Protection Agency, under which there is an Office of Energy. For Kentucky, this is the Energy & Environment Cabinet, which houses both the Department for Environmental Protection and the Office of Energy Policy. For Michigan, this is the Department of Environment, Great Lakes, and Energy.

oversight of Indiana's utilities, with a scope that is consistent with the institutions established across all neighboring states.

With regards to the clarity of state energy goals, four of the five states have promulgated an RPS, where Indiana has set a voluntary goal, while Illinois, Michigan, and Ohio have set mandatory goals. Despite the voluntary nature of Indiana's target, renewable deployment is set to continue going forward, driven primarily by declining technology costs and tightening environmental regulations for fossil fuel-fired generation, as discussed in Section 8.2.2. As a result, achieving the voluntary goal of 10% by 2025 is feasible. It is important to note that while most states in the region will meet their targets, they are certainly less ambitious when placed in the context of other states in the US, such as New York and California, which have targeted 100% carbon-free electricity by 2040 and 2045, respectively.[315] However, Illinois is considering 100% clean energy by 2050 through the *Clean Energy Jobs Act* (House Bill 3624) – this Bill is currently before the Illinois General Assembly[316] and has received Governor support.[317] In addition, Michigan Governor Gretchen Whitmer signed Executive Order 2020-10 in September 2020 to set the goal of economy-wide carbon neutrality by 2050.[318]

Finally, while four of the five states (Indiana, Kentucky, Michigan, and Ohio) have published a statewide energy plan, none seem to be currently active. If Indiana is to pursue the development of a refreshed energy plan, policymakers should consider the costs and benefits of a legislatively mandated process. The benefits of a state energy plan include transparency, stakeholder participation, and clarity on sector direction for the industry in general. However, there are costs associated with the time and resources needed to coordinate such an endeavor. Overall, the plan need not be overly long or complicated, but can help the state determine what its energy goals are, how to achieve them, and at what cost.

10.2 Considerations for energy policy

The following section reviews legislative efforts underway in various states which impact the electricity sector. These efforts can generally be grouped into the following categories, which are explored in the subsections below:

- **clean energy:** states focused on achieving clean energy goals have promulgated policies that encourage the deployment of renewables and focus on carbon reduction efforts. These policies are especially aggressive in the Northeastern region of the US;
- **market access:** some states have enabled market access for generators and customers through the unbundling of the wholesale power market, as well as the implementation of retail competition;

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[315] DSIRE. *Renewable & Clean Energy Standards.* September 2020.

[316] Illinois General Assembly. *HB 3624.*

[317] S&P Global. *Illinois governor details broad plan for clean power, utility oversight reform.* August 21, 2020.

[318] The Office of Governor Gretchen Whitmer. *Governor Whitmer Announces Bold Action to Protect Public Health and Create Clean Energy Jobs by Making Michigan Carbon-Neutral by 2050.* September 23, 2020.

- **treatment of legacy assets:** states have begun to address stranded cost issues, including enacting bills to allow for the securitization of these assets; and
- **alternative ratemaking regimes:** selected states across the US are moving from a cost of service regime to some form of performance-based ratemaking to determine electric rates.

10.2.1 Clean energy

> *"Perhaps the biggest trend in 2019 dealt with state initiatives to reduce emissions from the electric sector, with a handful of states taking sweeping, decisive action toward decarbonization."*
>
> Source: National Conference of State Legislatures. *2019 Legislative Energy Trends*. February 2020. p. 1.

Clean energy policy continues to be one of the most pursued state initiatives across the US. In 2019, legislatures across the country considered over 1,500 bills related to clean energy, renewable energy, or emissions reductions, with around 200 of these measures enacted or adopted during the legislative session.[319] As previously demonstrated in Figure 124, renewable and clean energy standards are a popular mechanism used to promulgate clean energy policy, with 34 states across the US adopting either an RPS or a CES, and a further eight states (including Indiana) adopting a voluntary renewable program. These standards are especially aggressive in the Northeastern region of the US, where states have set the following targets for renewable/carbon-free generation:[320]

- **Connecticut:** 40% by 2030, with a goal of reaching 100% carbon-free electricity by 2040;
- **Maine:** 100% renewable by 2050;
- **New Jersey:** 50% by 2030, with a goal of achieving 100% clean energy by 2050;
- **New York:** 70% renewable by 2030, rising to 100% carbon-free by 2040;
- **Rhode Island:** 38.5% by 2035, although the governor signed an Executive Order earlier this year committing the state to 100% renewable by 2030;[321] and
- **Vermont:** 75% renewable by 2032.

A number of companies have announced their intention to voluntarily achieve higher levels of decarbonization than states are targeting, often using methods like virtual power purchase agreements. However, renewable standards are not the only means through which legislatures impact clean energy policy. According to the National Conference of State Legislatures, states are increasingly focused on policies aimed at reducing greenhouse gas emissions, decarbonization, carbon pricing, ramping up energy efficiency measures, as well as supporting a clean energy economy through various mandates, incentives, and market-based strategies.[322]

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[319] National Conference of State Legislatures. *2019 Legislative Energy Trends*. February 2020.

[320] DSIRE. *Renewable & Clean Energy Standards*. September 2020.

[321] State of Rhode Island, Office of Energy Resources. *100 Percent by 2030 Renewable Electricity Goal*. <http://www.energy.ri.gov/100percent/>

[322] National Conference of State Legislatures. *2019 Legislative Energy Trends*. February 2020.

For example, with regards to carbon pricing, an estimated 17 states considered 40 related bills during the 2019 legislative session.[323] These bills proposed various policy mechanisms, including carbon taxes, fees, and cap-and-trade markets to decrease emissions. While half of these bills failed or were vetoed, the other half will be reconsidered in the next legislative session. The most extensive, mandatory cap-and-trade program in the US to date is the Regional Greenhouse Gas Initiative ("RGGI"), which commenced in 2009 and currently includes ten states in the Northeast.[324] The state-level program applies to electric power plants larger than 25 MW, with an RGGI Cap that "represents a regional budget for CO_2 emissions from the power sector."[325]

According to the World Bank, there are two main types of carbon pricing:

Emissions trading (or cap-and-trade) **systems** cap the total level of GHG emissions and allows those industries with low emissions to sell their extra allowances to larger emitters.

A **carbon tax** directly sets a price on carbon by defining a tax rate on GHG emissions or – more commonly – on the carbon content of fossil fuels.

Source: World Bank. *Pricing Carbon.*

The case studies explored in the textbox below highlight two examples of clean energy legislation in the US. The first focuses on legislation passed in Texas in 2005, which illustrates the impact deploying renewables can have on electricity rates in a competitive wholesale market environment. The second focuses on more recent legislation passed in New York in 2019, which embodies the trend towards more ambitious clean energy goals and demonstrates the mechanisms that can be implemented to ensure these targets are met.

The Competitive Renewable Energy Zone program in Texas

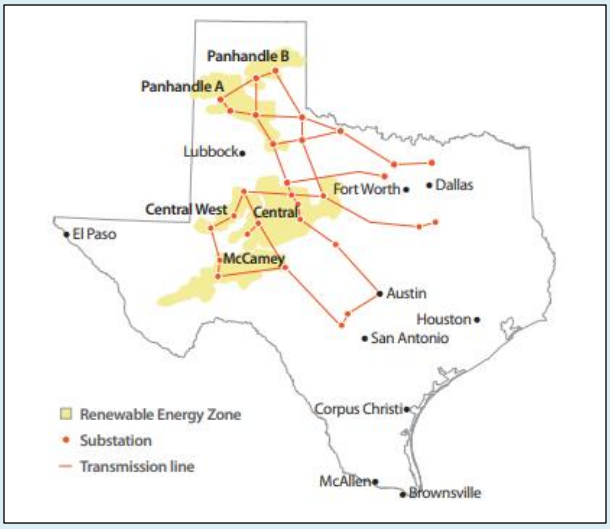
In 2005, the Texas State Legislature promulgated Senate Bill 20, which ordered the creation of Competitive Renewable Energy Zones ("CREZ") in an effort to increase the state's renewable capacity. These zones represented areas of the state with significant wind potential, concentrated primarily in West Texas. The Bill aimed to connect this abundant and generally untapped wind resource to the load centers located in Central and East Texas.

To do this, the state selected a $6.8 billion plan to build more than 3,500 miles of tranmission lines capable of transmitting around 18 GW of electricity to the populated regions of the state. The map below illustrates the transmission infrastructure installed under the CREZ program, which was completed in 2014 (see transmission lines in orange). *continued…*

[323] Ibid.

[324] States include Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island, and Vermont. (Source: RGGI. *Welcome.* <https://www.rggi.org/>)

[325] RGGI. *Elements of RGGI.* <https://www.rggi.org/program-overview-and-design/elements>



This major transmission investment enabled significant wind capacity to be built in Texas, allowing the state to surpass its original target of installing 18 GW of renewables under the CREZ program. As of 2019, Texas has installed over 28 GW of wind capacity.

The influx of renewable generation has contributed to lowering rates across the Electric Reliability Council of Texas ("ERCOT") region. Retail electricity prices in the state have decreased from 9.14 cents/kWh in 2005 (which marks the beginning of the CREZ program) to 8.8 cents/kWh in 2019.

Sources: USAID and NREL. *Renewable Energy Zone (REZ) Transmission Planning Process: A Guidebook for Practitioners.* September 2017; ERCOT. *The Texas Competitive Renewable Energy Zone Process.* September 2017; Powering Texas. *Transmission & CREZ Fact Sheet.* December 2018.

New York's Climate Leadership and Community Protection Act

In July 2019, the state of New York passed the Climate Leadership and Community Protection Act ("CLCPA"), which includes an RPS of 70% of load served by renewables by 2030, rising to 100% of load served by carbon-free resources by 2040. The CLCPA also outlines the following capacity targets:

- 6,000 MW of **distributed solar** capacity by 2025;
- 3,000 MW of **energy storage** capacity by 2030; and
- 9,000 MW of **offshore wind** capacity by 2035.

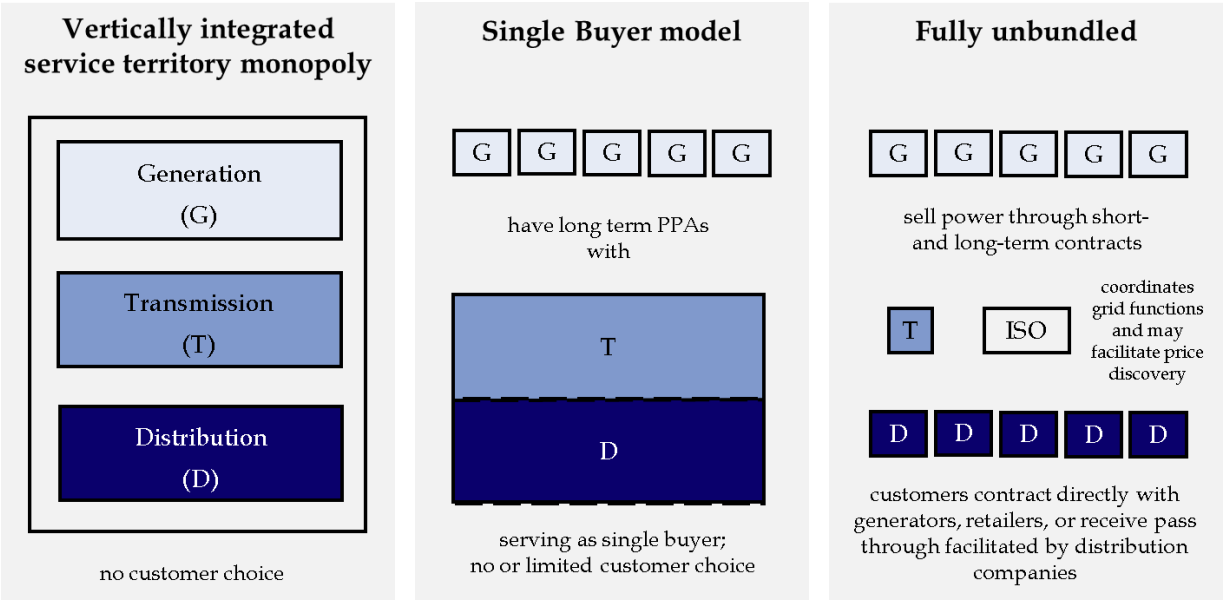
As part of these and previous RPS efforts, the New York State Energy Research and Development Authority ("NYSERDA") has run approximately 14 competitive solicitations over the 2005-2019 period. These annual procurements have resulted in the development of nearly 150 projects, totaling 6.5 GW of renewable capacity. In addition, NYSERDA launched its first statewide offshore wind solicitation in 2018, securing 1,696 MW of capacity, the single largest renewable energy procurement by any state. The state's second offshore wind solicitation launched earlier this year and seeks up to 2,500 MW of offshore wind capacity to bring New York closer to its clean energy goals.

Sources: NY State Senate. *Senate Bill S6599.* June 18, 2019; NYSERDA. *Solicitations for Large-scale Renewables.* <https://www.nyserda.ny.gov/All-Programs/Programs/Clean-Energy-Standard/Renewable-Generators-and-Developers/RES-Tier-One-Eligibility/Solicitations-for-Long-term-Contracts>

10.2.2 Market access

Legislation has also been used to enhance power market access for generators and customers to varying degrees. Generally, there are three main ways of organizing the electricity sector, as demonstrated in Figure 127 and described in further detail below.

Figure 127. Types of market design



The traditional **vertically integrated monopoly model** is one where the utility handles all aspects of the electricity value chain, from generation through to transmission and distribution. Under the **single buyer model**, IPPs compete to provide power through long-term power purchase agreements ("PPAs") to that single buyer entity, which may or may not be independent of the utility operating the transmission and distribution grid. Under the **fully unbundled model**, competition is introduced in the distribution sector. As a result, transactions between all parties, namely generators, customers, and intermediaries, take place relatively freely. On the demand side, customers can choose their electricity provider and negotiate their own contracts, while on the supply side, generators are able to sell their electricity to any market participants.[326] Additionally, under the fully unbundled model, an ISO is established to coordinate grid functions, among other responsibilities.

The electricity sector in Indiana does not fit neatly into any of these three models, and instead draws on a combination of elements from each. In this sense, Indiana's market is comprised of vertically integrated utilities (similar to the vertically integrated monopoly model), as well as a number of IPPs (similar to the single buyer model), all of whom are members of either MISO or PJM, which act as the ISOs for the region (similar to the fully unbundled model).

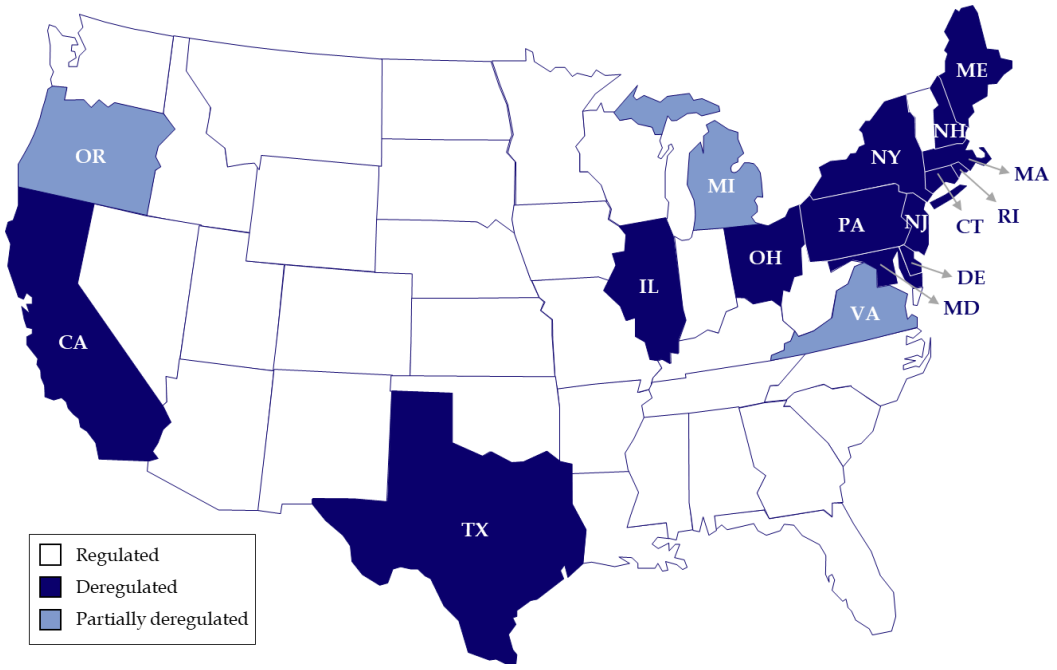
[326] International Energy Agency. *Energy Market Reform: Competition in Electricity Markets*. February 20, 2001.

To enhance market access, Indiana could: (1) deregulate the generation sector to create competition for the supply of power; and/or (2) implement some form of retail competition to allow customers to choose their desired electric service. These two legislative actions are explored in the subsections that follow, including specific examples of legislation promulgated in the US to achieve greater market access.

10.2.2.1 Wholesale competition

Indiana already has access to a wholesale energy market – IPPs already exist, and utilities are already participants in either MISO or PJM. Therefore, in order to move towards a fully unbundled wholesale electricity market, regulated utilities would need to divest their generation assets, or transfer them to a competitive affiliate. As defined by the US EPA, "utilities in deregulated markets are prohibited from generation and transmission ownership and are only responsible for distribution, operations, maintenance from the point of grid interconnection to the meter, and billing ratepayers."[327] This market structure creates competition for the supply of power and shifts some of the financial risks associated with building generation assets to private investors. Figure 128 indicates the states across the country that have deregulated their electricity markets to some degree.

Figure 128. Map of deregulated electricity markets



Notes for partially deregulated states: electric choice participation in **Michigan** is legislatively capped at 10% of a utility's average weather-adjusted retail sales; in **Oregon** and **Virginia**, electric choice is not available for residential customers.

Sources: Electric Choice. *Map of Deregulated Energy States & Markets.* Updated 2018; American Coalition of Competitive Energy Suppliers. *State-by-State Information.*

[327] US EPA. *Understanding Electricity Market Frameworks & Policies.*

Across the US, legislative efforts to introduce competition in the wholesale market began as early as the 1990s, as highlighted by the example in the textbox below. Some states, such as New York, pursued this restructuring effort through regulation as opposed to legislation.[328]

Electric industry restructuring in Connecticut

Deregulation of Connecticut's electricity market was initiated in 1998 through the promulgation of Public Act 98-28 (*An Act Concerning Electric Restructuring*). Under the legislation, the two electric utilities serving the state were required to sell off their generation assets and instead purchase power on the wholesale market alongside new competitive suppliers. The restructured utilities became known as Utility Distribution Companies, responsible for overseeing the delivery of electricity to Connecticut households and businesses.

The legislation was pursued with the overarching goal of reducing rates for customers, stating: "changes in generating technology now enable the provision of electric service at much lower rates than are currently being charged in Connecticut and competitive market forces can play a role in the reduction of Connecticut rates." (Section 2-3)

Sources: Connecticut Genral Assembly. *Public Act No. 98-28*. 1998; CT Energy Ratings. *Connecticut Deregulation History*. <https://www.ctenergyratings.com/resources/connecticut-energy-deregulation-history>

10.2.2.2 Retail competition

Retail electric choice allows customers to buy electricity from a competitive electricity supplier other than their incumbent utility. Across the country, this choice has taken many forms, which can be categorized into three types:

- **pure retail competition**: where customers across all segments (i.e., residential, commercial, industrial) are required to either choose a competitive supplier or have one assigned to them. This model is seen in ERCOT (Texas), where restructuring of the retail electric market began in 1999 with the passing of Senate Bill 7 (the *Texas Electric Choice Act*).[329] As of 2018, 116 competitive retail electric providers ("REPs") were operating in ERCOT, providing 315 unique product offerings.[330] In terms of success metrics, since the implementation of retail competition in the state, approximately 94% of customers have exercised their ability to choose their electric provider, and retail rates have decreased by 31%;[331]
- **hybrid retail model:** where customers are served by default by their incumbent utility but can choose an alternate power supplier. This model is seen in many of the Northeastern

[328] *See* New York PSC. *Case 94-E-0952: In the Matter of Competitive Opportunities Regarding Electric Service.* 1996.

[329] PUCT. *Scope of Competition in Electric Markets in Texas.* January 2019.

[330] Ibid.

[331] ERCOT. *Observed Selection of Electric Providers September 2017 – September 2018.* October 1, 2018.

states that have retail competition. For example, in Pennsylvania, retail choice was enabled through the *Electricity Generation Customer Choice and Competition Act* of 1996.[332] Through the legislation, customers are able to choose between remaining with their local utility company or switching to an independent electric generation supplier ("EGS"). By 2018, 115 EGSs were active in the state, with 33% of customers utilizing their ability to shop for competitive suppliers;[333] and

- **mass aggregation model**: where municipalities and counties are able to procure electricity from retail electric suppliers on behalf of their residential and small commercial customers. Aggregation programs are offered on both an opt-out and opt-in basis, although communities tend to favor opt-out programs. This model requires the lowest level of active customer engagement and has been seen in the Midwest (e.g., Illinois adopted this approach in 2009 through Section 1-92 of the *Illinois Power Agency Act*)[334] and now California (see textbox below – which highlights California's experience with mass aggregation as a means to procure more renewable energy).

Community choice aggregation in California

Community choice aggregation ("CCA") provides a means of *"aggregating the electric load of a community for the purpose of contracting for power that is greener and cheaper than the incumbent utility."* In California, CCAs are the sole alternative supplier to the local IOU for most customers, and function as an opt-out program.

CCA offerings can include solar net energy metering tariffs, feed-in tariff incentives for local solar projects, as well as energy efficiency and demand response programs. Generally, CCAs in California offer two levels of service:

- default service with a 35% to 55% renewable electricity offering; or
- a more expensive 100% renewable electricity option.

Sources: Lean Energy US. *CCAs and the Path to Local Economic Development and Energy Innovation: California Case Studies*; Lean Energy US. *California.* <https://leanenergyus.org/cca-by-state/california/>

The perceived benefits and challenges associated with retail competition are far-ranging. On the one hand, benefits can include reduced electricity prices to end consumers, heightened consumer choice, and innovation in the electricity supply sector (e.g., community solar, renewable gas). On the other hand, key challenges cited are the time and resources required to implement guiding regulatory processes, the need for stringent consumer protection rules, and the additional costs to utilities associated with billing procedures and metering infrastructure, which are needed to align with the product offerings from competitive retailers.

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[332] NARUC. *Pennsylvania's Retail Markets.* May 14, 2008.

[333] Pennsylvania PUC. *Retail Electricity Choice Activity Report.* 2018.

[334] Illinois General Assembly. *Illinois Power Agency Act.* August 28, 2007.

10.2.3 Treatment of legacy assets

Trends in tightening environmental regulations, historically low natural gas prices, and declining technology costs for renewables (as discussed in Section 8.2) have placed significant pressure on coal and nuclear power plants. As a result, utilities have had to consider the early retirement of these assets, as they become increasingly uneconomic. This has brought the risk of stranded costs to the forefront of the industry, where "events occurring after the utility's investment have left the utility unable to recover that investment, at least from the customers on whose behalf the investment was made."[335]

States across the country have dealt with this issue through varying legislative efforts. In the Midwest, states seem to be focusing on providing direct generation subsidies to support the continued operation of these uneconomic assets (see Section 6.3 for two examples from the region – Ohio's support for coal and nuclear plants through *House Bill 6*, and Illinois' legislatively mandated nuclear subsidies through the *Future Energy Jobs Act*).

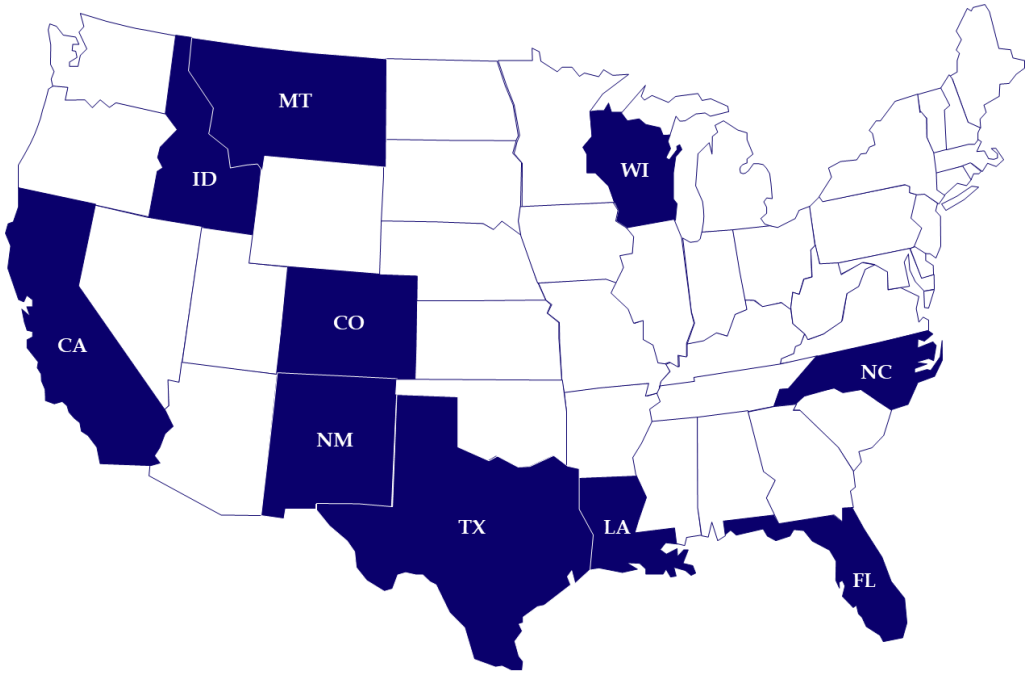
In contrast, other states have promulgated securitization legislation as another method for addressing the stranded cost issue. Securitization is a well-known approach to addressing stranded costs (or other extraordinary costs) in the US. It has been used to recover stranded costs associated with the liberalization of electricity markets, financing environmental control equipment, and more recently, paying for storm recovery costs.

Generally, securitization involves the creation of securitized ratepayer-backed bonds, which are financial assets created for the purpose of lowering current utility rates by using non-bypassable charges to refinance current assets over longer periods. Essentially, securitization is a risk and time reallocation process, achieved by deliberately carving out a part of the rate base and packaging it with more secure legal arrangements, possibly amortized over a longer period of time. Figure 129 highlights states with active securitization legislation, while the textbox below presents a relatively recent experience with securitization in the region (Michigan) that was pursued through regulation.

Non-bypassable charges: the repayment rate for the bond is generally non-bypassable by ratepayers unless the ratepayer completely disconnects from the grid. As long as entities are still connected to the utility's network, they would still be required to make bond payments at a rate determined by their consumption level prior to self-generation. This reduces demand change risk.

[335] Energy Regulation Quarterly. *From Streetcars to Solar Panels: Stranded Cost Policy in the United States.* September 2015. <https://www.energyregulationquarterly.ca/articles/from-streetcars-to-solar-panels-stranded-cost-policy-in-the-united-states>

Figure 129. Map of states with active securitization legislation



Sources: Utility Dive. *Securitization Fever: Renewables Advocates Seize Wall Street's Innovative Way to End Coal.* May 28, 2019; Daily Energy Insider. *North Carolina Governor Signs Storm Securitization Bill into Law.* November 8, 2019.

Michigan securitizes costs related to a nuclear contract buyout

In February 2017, Consumers Energy filed an application with the Michigan Public Service Commission ("MPSC") to securitize the costs related to the early termination of its power purchase agreement with Entergy for the Palisades nuclear power plant. Although the PPA was set to expire in 2022, Consumers Energy sought to terminate the agreement in 2018 and buy out the remainder of the contract term in order to take advantage of lower-cost resources.

MPSC approved the application in September 2017, allowing Consumers Energy to securitize around $142 million of the contract buyout costs, to be recovered from ratepayers over a six-year period. Although this decision increased rates in the short- to mid-term, the Commission determined that "authorizing Consumers Energy to buy out the remainder of the Palisades contract was in the best interest of its cutomers due to the expected long-term savings, and that securitization of the buyout costs will provide tangible and quantifiable benefits to customers." These savings were estimated at approximately $273.3 million.

Source: MPSC. *Issue Brief: Palisades Nuclear Plant.*

Securitization involves the following steps:

- **enabling legislation:** the state legislature passes a law that authorizes the use of securitization by utilities, which covers the ability to enforce non-bypassable tariffs onto consumers, authorizes the regulator to issue irrevocable finance orders, defines the types

of activities/assets for which the regulator is allowed to issue the finance order, identifies the legal and tax status of the legal entity housing the ratepayer-backed bond, and sets the standards of review for the regulator to issue the finance order;

- **issuance of the finance order:** once the asset (or in some cases a specific funding requirement, such as disaster relief) to be securitized has been identified, and the cost-benefit analysis of securitization has been studied, the regulator issues a financing order allowing the creation of the ratepayer-backed bond to raise a specific dollar amount, and specifying the dollar amount (minus any fees) to be removed from the rate base of the regulated utility;
- **creating the bond:** a special purpose vehicle ("SPV"), which is a legal entity created just for the securitization, is created to house the ratepayer-backed bond. The SPV is tailored to meet the criteria necessary to obtain the highest credit rating possible, including having strict articles of association, financial control standards, and restrictions on allowed activities. This ensures ratepayer-backed bonds can secure very high credit ratings and achieve low financing costs;[336] and
- **fundraising:** investment banks then market the bond to investors, and the funds raised are paid to the regulated utility to recover the costs associated with the securitized asset or funding requirement.

> **WACC:** the total cost, in percentage terms, of financing a regulated utility's assets. The predominant method for setting the allowed rate of return is to use the regulated firm's WACC, suggesting that the entity is being compensated for its capital costs.

While lowering the financing cost of a rate base asset by enhancing the credit, securitization can also help lower rates in the present by extending the repayment period. For example, if an asset in a utility rate base has a remaining economic life of five years, the asset value would be depreciated over that time, and the return on investment (weighted average cost of capital) and return of investment (depreciation) for this asset would be charged to ratepayers over the next five years. If the same asset is instead securitized into ratepayer-backed bonds with a ten-year maturity, and the value of this asset is removed from the rate base of the regulated utility, the asset's burden to ratepayers over the next five years would be reduced. However, the ultimate total burden onto ratepayers over the ten-year period could be higher, depending on the difference between the regulated utility's approved WACC and the interest rate of the ratepayer-backed bond. Current low interest rates on high quality debt improve the potential economics of securitization.

Fundamentally, there is no "magic" in the securitization process or the creation of ratepayer-backed bonds. Therefore, there are tradeoffs that regulators, electric utilities, and ratepayers should consider before committing to securitization. These tradeoffs include:

- **amortization period, trading lower rates for higher overall payments over time**: if the interest rate of the ratepayer-backed bond is not low enough, the securitization process

[336] LEI's research indicates that except for one instance, all ratepayer-backed bonds issued in the US related to electric utilities have achieved and maintained AAA credit ratings from credit rating agencies.

would become a tradeoff as a longer repayment term could lower rates in the short term, but ultimately result in higher costs over time. This outcome could create an intergenerational fairness issue as future ratepayers who may have never benefited from the securitized asset would have to bear the cost of financing the asset;

- **regulators would have less control over a portion of rates once securitized:** in order to secure a high credit rating for the ratepayer-backed bonds, regulators would give up control over the non-bypassable charges associated with the securitization, by putting in force an irrevocable finance order with an automatic adjustment mechanism. This means regulators would not be able to influence that portion of the rates; and
- **the cost/benefit of retiring the securitized asset must be taken into account**: should the securitized asset be retired, the cost of procuring replacement services (such as energy or capacity provided by a generation asset prior to its retirement) must be taken into account. These costs may, however, be offset by the decrease in operating and maintenance costs of the retired asset. As such, the ultimate cost/benefit analysis of retirement and securitization must be performed holistically, considering all cost impacts to ratepayers.

10.2.4 Alternative ratemaking regimes

As discussed in Section 6.2, electric rates in Indiana are determined using the traditional cost of service approach along with several pass-through charges. Although the IURC is authorized to approve performance incentives for energy efficiency programs (under *Senate Enrolled Act 412*), it is LEI's understanding that only one incentive has been approved to date.[337] IC 8-1-2.5 also sets out the Alternative Utility Regulation, which as discussed in Section 6.2, allows the IURC to do the following:

- "[a]dopt alternative regulatory practices, procedures, and mechanisms"; and
- "[e]stablish rates and charges based on market or average prices, price caps, index based prices, and prices that use performance based rewards or penalties … and are designed to promote efficiency."[338]

However, LEI understands that no utilities have proposed or adopted (through an alternative regulatory plan) any of the performance-based ratemaking ("PBR") aspects of the regulation to date.[339]

Selected states across the US are actively considering or have moved from COS to alternative ratemaking regimes, such as PBR – as demonstrated in Figure 130. Some of these states have or are pursuing this transition through legislation, such as Illinois (see discussion below) and Hawaii (through its legislatively mandated PBR regulatory proceeding).[340] Of particular relevance to

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[337] *See* National Conference of State Legislatures. *State Policies for Utility Investment in Energy Efficiency.* April 2019.

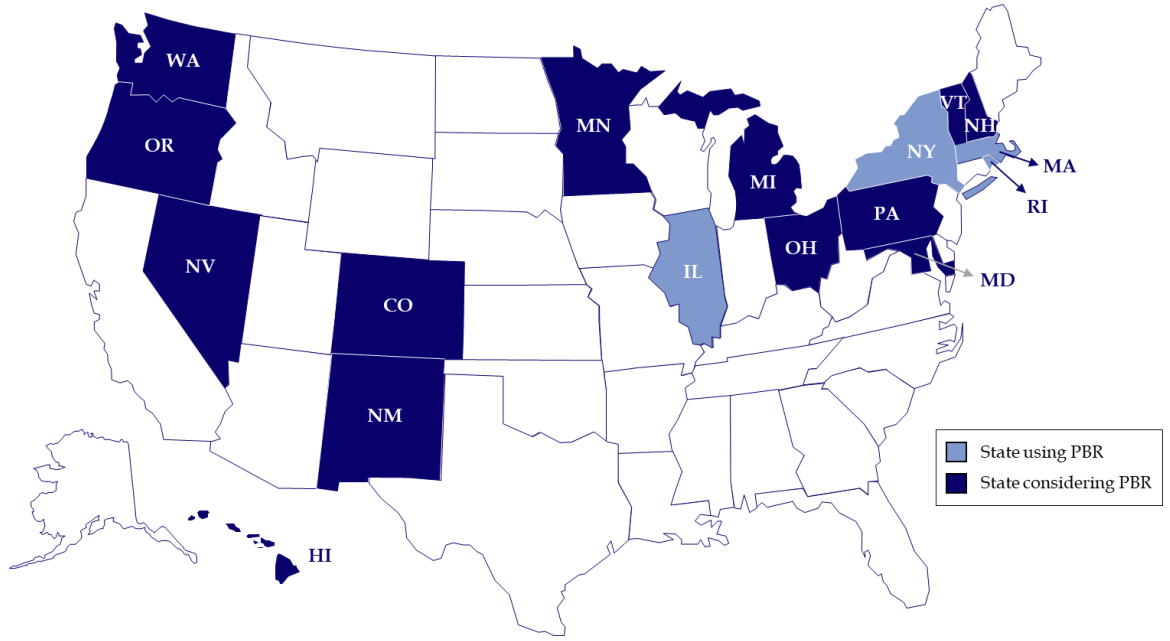
[338] IGA. *Indiana Code 2020 – IC 8-1-2.5-6.* <http://iga.in.gov/legislative/laws/2020/ic/titles/008#8-1-2.5>

[339] LEI correspondence with IURC Assistant General Counsel (September 30, 2020).

[340] Utility Dive. *Performance-based Regulation: Seeking the New Utility Business Model.* July 23, 2019.

Indiana are the PBR regimes present in Illinois, Michigan, and Ohio. We introduce the PBR concept first, and then discuss these regional examples thereafter.

Figure 130. Map of states using or considering PBR

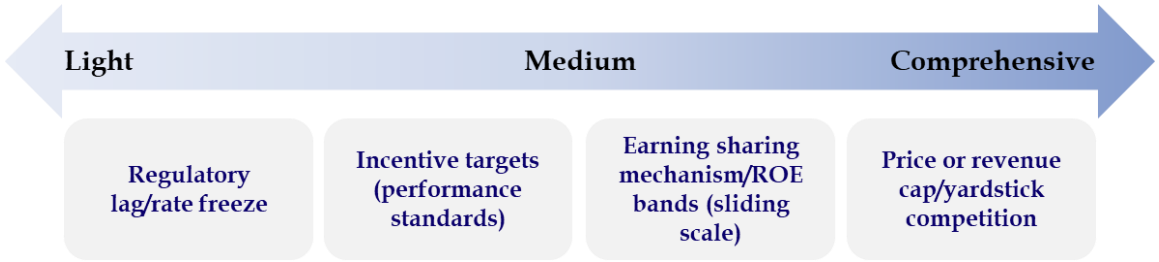


Source: EnerKnol and Wood Mackenzie Power & Renewables. *Regulatory Evolution for a Decentralized Electric Grid: State of Performance-based Ratemaking in the US*. June 13, 2019.

PBR is a regulatory approach that aims to provide incentives for regulated utilities to improve their overall efficiency. PBR can come in many flavors, depending on how "performance" is defined and the intensity of the incentive mechanisms. However, the process of defining performance is the first step in implementing any PBR approach. Generally, the main goal of PBR is to rectify what have come to be understood as the two foundational problems with traditional COS, alternatively referred to as "rate base rate of return regulation:" (1) incentives for cost-efficiency are weak, and (2) the associated administrative process is intensive. These two problems are overcome by minimizing the direct linkage between costs and rates, and by shifting the balance of the ratemaking process away from one that investigates costs to one that sets a partly pre-determined (formulaic) path for rate growth based on embedded productivity targets and capital expansion needs. Properly designed, PBR helps align utility incentives with customer objectives.

Implementation of PBR need not be complex. PBR is best conceptualized as a continuum, ranging from "light" to "comprehensive" mechanisms, rather than a single type of regulatory regime. This continuum is illustrated in Figure 131 and described in further detail below. Notably, a simple set of performance incentive mechanisms with rewards represents a form of PBR and can create incentives for regulated utilities to perform efficiently and meet policy objectives.

Figure 131. Overview of possible PBR approaches



In terms of **light mechanisms**, options available to regulators include either a regulatory lag or a rate freeze. A regulatory lag essentially allows for a delay in introducing new rates. The lag provides a utility a longer horizon to plan, operate, and keep the benefits of the incentives provided in PBR. Likewise, through a rate freeze, a utility's rates are held constant during the PBR term. A rate case moratorium is similar to a rate freeze, in that it represents a commitment not to initiate a rate case. Such mechanisms give strong incentives to reduce or control operating costs. Rate freezes are also commonly used to protect consumers during transition (i.e., transition to retail competition). However, without inflation adjustments, lengthy terms can impose risks on the regulated firm, particularly if substantial capex is required.

As for **medium mechanisms**, options include performance standards, as well as earning sharing mechanisms ("ESMs"). The former, a COS approach with performance standards, ensures that any cost reductions implemented by the utility do not lead to a deterioration of service quality. With performance standards, payments to utilities are adjusted upwards or downwards in correspondence to their level of performance. In contrast, ESMs allow customers to share in a company's earnings in excess of a pre-determined threshold return on equity ("ROE") through lower rates in subsequent years. Some ESMs also require customers to bear a portion of any shortfall of earnings below a certain ROE threshold.

Finally, in terms of **comprehensive mechanisms**, options include either a price cap or a revenue cap. Under a price cap, the PBR formula adjusts rates for each year during the regulatory period, taking into account changes in inflation and changes in productivity. Typically, price caps apply to a basket of services over which it is averaged, giving the utility a degree of flexibility in how to optimize specific customer rates and consider cost allocations. Under a price cap regime, the utility bears the volumetric risk, but is rewarded during periods of high demand growth.

In contrast, under a revenue cap regime, the PBR formula adjusts revenues according to a predetermined formula, taking into account changes in inflation and productivity, and rates are recalibrated automatically. Under a revenue cap, there is no incentive for utilities to maximize sales, but there is still an incentive to minimize overall costs, making it arguably more compatible with utilities that are facing substantial demand response programs or energy efficiency reductions in consumer demand. Revenue cap regimes provide more pricing flexibility and are preferable when costs do not vary significantly with sales volumes.

Notably, a newer generation of PBR, outcomes-based PBR, is emerging in jurisdictions around the world. Under this mechanism, the focus is on the outcomes rather than the inputs to the

revenue requirements. The utilities under outcomes-based PBR are expected to achieve the outputs that are set during the PBR filing (or before the implementation of PBR). These outcomes could be grouped into different categories, such as reliability and availability, operational effectiveness, safety, public policy responsiveness, customer satisfaction, financial performance, and environmental impact, to name a few.

In the region, the following states have adopted, or are in the process of exploring PBR regimes:

- **Illinois:** Illinois first implemented its PBR regime in 2011 through the passage of the *Energy Infrastructure Modernization Act*. Under the Act, the state created performance incentive mechanisms ("PIMs") and a formula rate focused on grid modernization, whereby two of the state's IOUs were penalized only if they failed to improve reliability.[341] In 2016, the *Future Energy Jobs Act* shifted focus to energy efficiency, and set out both reward and penalty PIMs for the two utilities depending on whether they reach their pre-determined energy efficiency targets;[342]
- **Michigan:** in contrast, PBR development in Michigan is still in a stakeholder engagement phase. In 2019, Governor Whitmer and the MPSC launched MI Power Grid, a multi-year stakeholder initiative that considers PBR as one of the options to optimize grid investments and performance in the state.[343] Prior to this, the state's legislature passed *Public Act 341* in 2016, requiring the MPSC to conduct a study addressing PBR and its potential applicability in Michigan.[344] The final report was released in 2018 and presented recommendations in addition to the PIM variations already used sporadically in the state, which are primarily focused on energy efficiency, reliability, and most recently, demand response;[345] and
- **Ohio:** similar to Michigan, PBR development in Ohio is still in an early exploratory stage. In 2018, the Public Utilities Commission of Ohio ("PUCO") published Power Forward: A Roadmap to Ohio's Electricity Future, which among other policy positions, expressed the Commission's desire to implement PBR in the state.[346]

Regardless of the mechanism chosen, the PBR approach has several perceived advantages over a traditional COS approach, as illustrated in Figure 132. In addition to motivating larger efficiency improvements among utilities than traditional COS, PBR is expected to constrain rate increases for customers in the long run and bring commercial success to those utilities that are able to exceed industry expectations on productivity. PBR can also align utility incentives with state

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[341] Ibid.

[342] ACEEE. *Snapshot of Energy Efficiency Performance Incentives for Electric Utilities.* December 2018.

[343] MPSC. *MI Power Grid Flyer.*

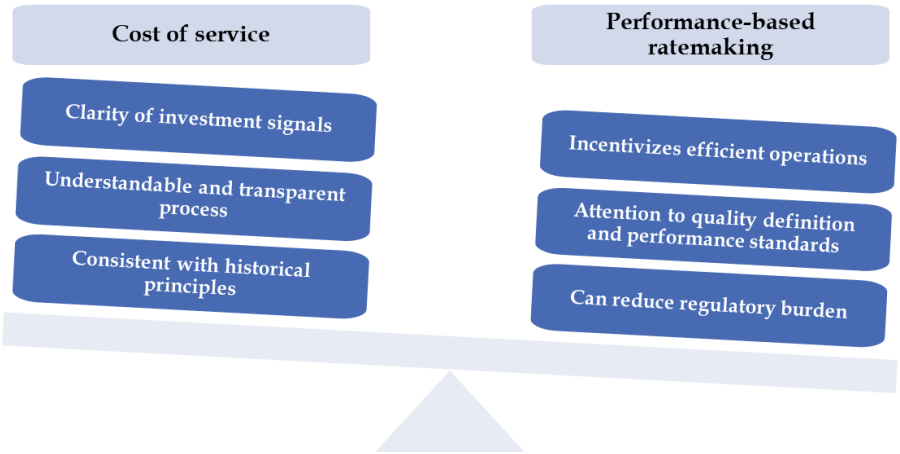
[344] MPSC. *Performance Based Regulation Report.*

[345] ACEEE. *Performance Incentive Mechanisms for Strategic Demand Reduction.* February 2020.

[346] PUCO. *Power Forward: A Roadmap to Ohio's Electricity Future.* August 29, 2018.

policy objectives and reduce the regulatory burden on both utilities and regulators by decreasing the need for frequent regulatory hearings.

Figure 132. Comparison of COS and PBR benefits



Aside from PBR, another alternative approach to ratemaking stems from revenue decoupling. Decoupling is a revenue adjustment mechanism that, as defined by the IURC, "separates fixed cost recovery from the amount of electricity or gas the utility sells. By appropriately separating fixed and variable costs, utilities will be protected if their sales decline because of customers efforts to reduce energy use and/or to reduce demand."[347] As such, decoupling is intended to provide substantial risk-mitigation benefits for both utilities and consumers by allowing utilities to become financially indifferent to the quantity of energy they sell. In Indiana, decoupling mechanisms to date have been approved for gas utilities, but not for electric utilities.[348, 349]

While decoupling mechanisms implemented throughout the country are uniform in their general definition and objective, there is substantial variation in their design and application. The design process of a decoupling mechanism involves a series of decision points that will vary based on policy and stakeholder priorities. One standard method involves setting rates according to a permitted revenue per customer, rather than setting rates by units sold. With this technique, the regulator sets an allowed revenue per customer and then implements price adjustments according to whether the utility sold more or less energy than expected.

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[347] IURC. *Indiana Utility Guide.* 2019 Edition.

[348] Natural Resources Defense Council. *Gas and Electric Decoupling.* August 24, 2018.

[349] Most recently, the IURC denied Duke Energy's request to implement a revenue decoupling mechanism on the grounds that it was "not in the public interest because it would allow the Company to recover revenues for reductions in energy consumption that were not caused by its conservation efforts." (Source: IURC. *IURC Issues Order in Duke Energy Indiana Rate Case.* June 29, 2020)

10.2.5 Lessons learned

Indiana benefits from the ability to observe what has worked and what has not in other jurisdictions. While exhaustive treatment of this topic is beyond the scope of this paper, LEI believes that the following observations should be considered when designing policies in the four areas discussed above:

Clean energy: US states have generally failed to take a least cost, technology neutral approach to clean energy. RPS regimes and procurements have targeted favored industries rather than seeking the maximum environmental benefit at least cost. By contrast, carbon pricing (whether through a tax or cap and trade) allows the market to decide which technologies are best suited to address climate targets. For those states interested in pursuing clean energy goals, if a carbon pricing regime is not politically feasible, a single clean energy portfolio standard based solely on zero emitting characteristics, and resulting in a single REC category rather than several, would be best. This regime would also enable participation by carbon capture and storage. If Indiana chooses to incorporate clean energy policies going forward, it should avoid many of the approaches currently in use in other US states.

Market access: market opening must be associated with gradual exposure of customers to price volatility, and particular attention should be paid to access of small customers to hedges. A spot price pass through regime forces all customers to consider hedging with retailers, but small customers need access to information clearinghouses, normally set up by state regulators initially, to facilitate switching. States which have allowed for a default option (the option for those customers who do not select a retailer) based on rolling three year average prices have stabilized outcomes for small customers, though at the cost of undermining competition for small customers.

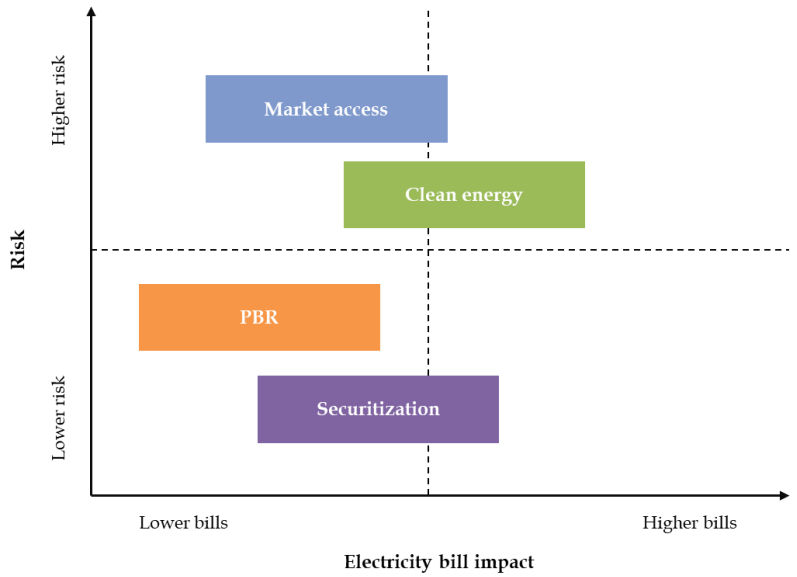
Treatment of legacy assets: methods for managing stranded costs in the context of wholesale market opening are well established, consisting of a mix of contracts between above market assets and customers to manage price volatility, and competitive transition charges (surcharges on customer bills to recover stranded costs which can be securitized). In the context of continued cost of service regulation, securitization can also be used to manage rate impacts of asset retirement prior to the end of its accounting life. However, doing so can raise intergenerational equity issues.

Alternative ratemaking regimes: properly designed alternative ratemaking regimes can help hold rate increases below inflation while sharpening utility focus on performance standards. However, such regimes are best crafted by regulators rather than through the legislature; legislation can for example specify that regulators are allowed to deviate from cost of service ratemaking to take into account efficiency standards, but should allow the regulator broad latitude in developing such standards. Regulators should also resist the temptation to develop complex alternative regimes that seek to micro-manage utility behavior while ostensibly giving utilities greater freedom from outdated regulatory processes. Intervenors also need to be open to process innovation if alternative ratemaking is to be properly implemented. All parties need to be attentive to implementation challenges, which suggests that initial PBR periods should start with a simple foundation which can be built upon in subsequent periods.

10.2.6 Review of policy implications

Based on the above observations, four categories of legislative actions discussed throughout this section were evaluated across two dimensions: (1) the perceived risks associated with its implementation; and (2) the impact it could have on electricity bills going forward. Figure 133 provides a graphical summary of this high-level assessment, which is discussed in further detail below. It is important to note that ultimately, the magnitude of risk and overall impact on electricity bills stemming from each of the policy actions will depend on numerous interacting factors – we address a few of these nuances in the discussion below.

Figure 133. Risk versus bill impacts of various policy actions



Clean energy policy (Section 10.2.1) is among the more challenging policy actions considered throughout this chapter, as given the intermittent nature of renewables, the uncertainty surrounding grid reliability rises at higher levels of their deployment. The impact on electricity bills is also potentially greater for clean energy policy than the other policy actions considered (market access, PBR, and securitization); while the costs of renewables are declining (as covered in Section 8.2.2), the inevitable costs incurred to firm up power (i.e., backstopping the variable generation from these renewables with dispatchable, flexible resources) will place upward pressure on prices. In this sense, any policy that diverges from a least-cost, technology neutral approach will ultimately increase costs for the system as a whole.

As for **market access** (Section 10.2.2), introducing competition in the supply of power should, in theory, lead to more competitive electricity rates. This will be contingent on several factors, including, but not limited to: whether a gradual phasing in of competition over time is necessary, to avoid stranding legacy generation assets as customers switch to competitive suppliers; and the degree to which the regulator will need to provide adequate protection from market power abuse, to ensure robust competition. The risk involved in enhancing market access for generators and customers will inevitably depend on the degree of expected volatility and the ability of customers

to hedge. The greater the exposure of smaller customers to competition, the more complex the legislative and regulatory framework may need to be,. As such, market access is arguably the riskiest policy action of all those considered in this chapter.

With regards to the **treatment of legacy assets** (Section 10.2.3), securitization should only be pursued if a holistic cost/benefit analysis of an asset retirement demonstrates clear benefits to customers. In this case, securitization can be an effective way to reduce the costs of stranded uneconomic assets compared to the asset remaining in a utility's ratebase only pursued if it benefits customers. However, the tradeoff arises from the uncertainty of whether securitization will raise rates in the future and by how much. As such, care should be taken in allowing the utility to grow its rate base following the securitization process, as the utility rate base needs to stay commensurate with the needs of customers.

Finally, for **alternative ratemaking regimes** (Section 10.2.4), PBR should be designed to better align the incentives for utilities with those of their customers, resulting in lower rates over time than would be achieved under a traditional COS approach. Consequently, the electricity bill reduction impact is greatest under PBR as compared to the other policy actions. Ultimately, the choice of a "light" versus a "comprehensive" PBR regime is determined by the risk appetite of the utility and the regulator, the range of incentives that the regulator is willing to approve, and the demands of and feedback from interveners. The "light" and "medium" forms of PBR can be thought of as stepping-stones towards a more "comprehensive" PBR regime. Thus, the risks associated with implementing PBR will depend on the approach chosen along the continuum, with risks increasing as more comprehensive mechanisms are implemented.

Key takeaways

- There are no anomalous entities in Indiana. Existing institutions (namely the IURC, OED and IDEM) are likely sufficient for the effective monitoring and oversight of Indiana's utilities. Specifically, the IURC's role in utilities regulation is consistent with the equivalent institutions seen in Indiana's neighboring states (i.e., Illinois, Kentucky, Michigan, and Ohio).
- Indiana, Illinois, Michigan, and Ohio each have promulgated an RPS through legislation. Despite the voluntary nature of Indiana's goal, it is consistent with targets common in the region, which range from 8.5% by 2026 (OH) to 25% by 2026 (IL). Notably, Illinois is currently considering 100% clean energy by 2050 through the *Clean Energy Jobs Act*, although this Bill is still before the Illinois General Assembly. In addition, Michigan's Governor issued an Executive Order in September 2020 setting the goal of reaching economy-wide carbon neutrality by 2050.
- In terms of considerations for future energy policy in Indiana, legislative efforts to impact electricity rates can generally be grouped into the following categories:
  - **clean energy:** the most ambitious targets are being set in the Northeastern US, such as New York's goal of reaching 100% carbon-free electricity by 2040, but utilize economically inefficient means to reach the goal;
  - **market access:** some states have enabled market access for generators and customers through the introduction of varying levels of wholesale and retail competition. In the region, this has been implemented in some form in Illinois, Michigan, and Ohio;
  - **treatment of legacy assets:** states in the region have implemented controversial subsidies for uneconomic coal and nuclear assets (e.g., Ohio House Bill 6, Illinois *Future Energy Jobs Act*) which have added to costs, while other states across the country have enacted bills to allow for the securitization of these assets instead; and
  - **alternative ratemaking regimes:** most states in the region (Illinois, Michigan, and Ohio) use or are in various stages of exploring the implementation of performance-based ratemaking mechanisms.

11 Goals, interests of key stakeholders, and potential paths forward

11.1 Goals and stakeholder sensitivities

There are a number of goals related to the electricity sector that stakeholders broadly share, such as reliability, affordability, rate predictability, compliance with existing laws, and accessibility. However, there are other areas where interests may diverge. Utilities generally seek to retain their historical role, and to resist diminishing statutory franchise privileges. By contrast, non-utility generators seek space to expand their business opportunities, both with utilities and with end consumers. Industrial consumers seek rates that are competitive with the jurisdictions in which their peers operate, while receiving a level of service which does not unduly interrupt their operations. Unions seek to maintain or increase member employment, remuneration, and benefits. Fuel and equipment suppliers advocate for a greater reliance on their associated generating technology. Municipalities seek to maintain their tax base while benefiting from rates that are low enough to attract business and avoid burdening residents. Environmental advocates focus on reducing emissions and effluents, while social justice advocates focus on affordability, and landowners split between those who welcome development if fairly compensated and those who oppose any kind of development nearby.

As stakeholders are not homogenous groups, Figure 134 presents a non-exhaustive sample of stakeholder advocate groups along with samples of statements they have put forward from a recent Duke rate case, provided solely for reference purposes. A selection of stakeholder groups along with some of their objectives or areas of concern are then presented in Figure 135.

Figure 134. Sample of stakeholder advocate statements from Duke's 2019 rate case

Stakeholder type	Example stakeholder advocate	Sample stakeholder statement
Local fuel suppliers	Indiana Coal Council	*The choice and installation of pollution control equipment and the existence of possible alternatives* ***can impact the ability*** *of Duke* ***to continue to burn Indiana-produced coal*** *and the economic useful life of its coal-fired generation plants.*
Industrial consumers	The Duke Industrial Group	*As industrial customers of Duke, members of the Industrial Group are reliant upon Duke for* ***consistent, reliable and reasonably priced utility service to support their respective operations*** *.*
Environmental advocates	The Environmental Working Group	*EWG educates consumers on policies that* ***promote and support emissions-free energy*** *because it saves ratepayers money and is better for human health and the environment*

Sources: Petitions to intervene of the Indiana Coal Council, Duke Industrial Group, and Environmental Working Group, from Duke's 2019 rate case [IURC Cause no. 45253]

Figure 135. Stakeholder groups and objectives/concerns

Objective	Stakeholder grouping							
	Utilities	IPPs	DER developers	Municipalities	Local fuel suppliers	Environmental advocates	Industrial consumers	Small customer advocates
Reliability	✓			✓			✓	✓
Cost	✓			✓			✓	✓
Retain role, resist diminishing statutory franchise privileges	✓							
Space for new entry		✓	✓				✓	
Reliance on specific technology/fuel					✓			
Local tax base retention	✓			✓				
Emissions and effluents reduction	✓	✓	✓	✓		✓	✓	

Consequently, evolving electricity regulatory policy is a process of constrained optimization in which sound policy seldom leaves any group completely satisfied. A number of the goals themselves are oppositional; for example, increasing reliability also increases costs; competition increases choice and may lower cost, but also increases volatility; stringent siting restrictions may reduce opportunities for municipalities to increase their ratebase; protecting existing resources may reduce opportunities to benefit from technological change. In some cases, challenges arise because the electricity sector is being used to meet other objectives, including economic development, job retention, shouldering a disproportionate share of carbon emissions reductions, assisting low income customers, or supporting municipal revenues. Many of these objectives could be addressed more efficiently outside of the electricity sector rather than being paid for indirectly on customer bills.

11.2 Indicative paths forward

To think more tangibly about stakeholder interests and evolution of the Indiana electricity sector, we have developed five alternative pathways that Indiana could consider. The pathways are not mutually exclusive; elements could be assembled from each to create additional scenarios. However, the pathways are intended to be internally consistent alternatives which vary in their attractiveness to different stakeholder groups. They also mirror in some ways some of the cases explored by the SUFG and LBNL on behalf of the IURC for its submission to the 21st Century Task Force. For reference, a summary of the scenarios explored by the SUFG and LBNL are presented in Figure 136.

Figure 136. SUFG and LBNL scenarios and comparison against their respective references

State Utility Forecasting Group

Scenario	Comparison against reference scenario	Impact on electricity prices and rationale (compared to reference)
Reference	n/a	n/a
Low Renewables Cost	Lower renewable capital costs and more aggressive cost reduction trajectory	Lower renewable costs lead to lower prices in the medium to longer term, with price gap growing over time
2025 Coal Retirement Moratorium	Assumes coal is not allowed to retire prior to the end of 2025 (with exception of Gallagher 2 and 4, Rockport 2)	In general slightly higher (1%-2%), as the costs associated with extending the life of the affected units offset the cost of the replacement capacity
2030 Coal Retirement Moratorium	Assumes coal is not allowed to retire prior to the end of 2030 (with exception of Gallagher 2 and 4, Rockport 1 and 2)	Some impact in the short term (2021-2024, where prices are between 1% and 4% higher), but minimal impact after that
Additional Energy Efficiency	More aggressive utility EE efforts, assuming double the amount of utility EE with the exception of NIPSCO's EE	Some impact in the short term (through to 2024, where prices are between 2% and 3% higher), less than 1% higher after that. While electricity prices are higher, electricity usage is lower; therefore, customer bills may be lower
Industrial Self-Generation	Explores more significant levels of self-generation in the industrial sector	Higher prices in the long-term (commencing in 2026, continuing and growing through to 2037; higher by between 1% and 7%)
High Natural Gas Price	Higher natural gas prices	Sensitivities incorporating higher natural gas prices and carbon pricing regimes lead to higher electricity prices
Carbon Price Sensitivities	Introduction of carbon prices	

Lawrence Berkeley National Laboratory

Scenario	Comparison against reference scenario	Overall economic impact (compared to reference, for 2040)
Reference	n/a	n/a
High Electrification	Higher demand	**Higher system-wide costs**, although focused on generation due to larger peaks that require new generation capacity
High PV Stress Test	Higher solar PV penetration	**Lower total system costs**, largely due to solar offsetting the need for new generation resources
Battery Storage Arbitrage	Storage breakthrough, higher storage penetration	**Lower total system costs**, largely due to solar offsetting the need for new generation resources
High PV and Battery Storage	Higher solar PV penetration with storage breakthrough	**Minimal** impact
Boundary Case (Distribution System Stress Test)	Very high PV, storage, electrified demand	This case was presented as a stress-test with very high adoption levels. Therefore, results in much **higher system-wide costs**, split relatively evenly between generation and transmission investments

Source: IURC. *2020 Report to the 21st Century Energy Policy Development Task Force*. August 14, 2020

The pathways vary in the extent of sectoral disruption and their primary objective function; while change would be most gradual under the enhanced status quo pathway, the aggressive decarbonization and the competitive wholesale market pathways would be the most disruptive. Below, we first describe the pathways. Next, we assess the pathways relative to potential goals. Finally, we map the pathways against stakeholder interests.

11.2.1 Path 1: Enhanced status quo

Under the enhanced status quo, the sector would be configured as follows:

- Traditional utilities remain primary engine of new investment in sector
- Existing regulatory regime would be reviewed to increase incentives compatibility with focus on efficiency and customer experience
- IRPs focus on comparing shorter duration and longer-lived capital investments, so as to assess tradeoff in cost to consumer of maintaining optionality
- Utilities face strengthened mandate to consider non-wires solutions to distribution investment
- Wherever possible, utilities encouraged to consider third party ownership alternatives to direct investment, and justify why utility direct investment provides the best outcome for consumers.

11.2.2 Path 2: DER-centric

Path 2 would include all of the elements of Path 1, but would be focused on increasing opportunities for DERs, provided doing so does not result in cross subsidies. Additional elements of Path 2 relative to Path 1 would include the following:

- Standardized interconnection procedures, including detailed utility cost justification, and potential for DER proponents to expeditiously challenge interconnection cost assessments
- Performance standards including timing for cost estimates and for ultimate interconnection fieldwork
- Bill credits for excess generation at locational marginal wholesale price, with owner retaining environmental attributes
- Utilities required to develop publicly available dynamic maps of their system to show areas of constraint and need, and to develop means of compensating DERs when used to alleviate system stress
- Utilities required to develop EV charging tariffs which provide time of use rates to shift charging to off peak periods

11.2.3 Path 3: Baseload preservation

Path 3 would include all of the elements of Path 1, but add the following:

- Utilities required to include in IRPs assessment of plans for life extension and efficiency improvements at existing coal and nuclear stations
- State to explore whether contracts with similar resources in neighboring states facilitate rate stability and economic development in Indiana
- State to examine least cost way of obtaining carbon offsets and have contingency plan in place should national legislation be forthcoming
- State to examine whether incentives for carbon capture and storage, development of small modular nuclear reactors, and hydrogen production and usage are beneficial to baseload preservation and economic development

Note: This path is related to the two coal retirement moratorium cases run by the SUFG.

11.2.4 Path 4: Aggressive decarbonization

Path 4 would include all elements of Path 1 and Path 2, as well as the following:

- Indiana would set a specific year to target reaching net zero emissions within the state across its economy, along with interim targets
- Utilities would be required to show in their IRPs how their plans are consistent with the net zero framework
- Indiana would join the Regional Greenhouse Gas Initiative ("RGGI"),[350] placing a price on carbon and joining a multistate trading area
- Revenues from RGGI permit sales would be devoted to a coal industry workforce transition fund
- State would explore the possibility of supplementing Federal Section 45Q tax credits[351] for CCS to encourage facilities to be sited in Indiana
- Indiana would review whether additional incentives for electric vehicle adoption provide net benefits to the state, and assess barriers to market-driven adoption in response to carbon pricing

Note: The SUFG Carbon Price Sensitivities are relevant to this path.

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[350] As covered in Section 10.2.1, RGGI is a mandatory cap-and-trade program which currently includes the following 10 Northeastern states: Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island, and Vermont. An alternative would be to join an ISO-led initiative.

[351] As covered in Section 8.2.4, Section 45Q of the Internal Revenue Code provides a tax credit on a per-ton basis for CO_2 that is captured and either: stored in a secure geologic formation; or utilized for enhanced oil/natural gas recovery or in direct air capture projects.

11.2.5 Path 5: Competitive wholesale market

Path 5 would incorporate all elements of Path 1 and Path 2, except that IRPs would be discontinued, and add the following:

- Utilities would be required to unbundle their generation portfolios and sell them or move them to a competitive subsidiary, in return for a stranded cost settlement
- Stranded costs would be securitized and amortized in such a way as to provide an immediate and meaningful bill discount to all consumers[352]
- All customers allowed to shop for power from competitive retailers; for industrial and commercial customers who fail to do so, power would be provided at pass-through wholesale rate, while residential customers who fail to switch would be supplied through periodic auctions ultimately resulting in rolling three-year blended average contracts
- IURC to establish a website to facilitate comparison shopping among retailers

Figure 137 presents the potential impacts of these five pathways on the role of utilities, regulatory framework, and costs.

Figure 137. Comparing changes to utility role, regulatory framework, and cost across pathways

	Path 1	Path 2	Path 3	Path 4	Path 5
	Enhanced status quo	DER-centric	Baseload preservation	Aggressive decarbonization	Wholesale competition
Role of utility	Unchanged	Added role of coordinating DERs	Unchanged	Adds role of procurement agent for zero emissions resources	Wires only
Extent of change to regulatory framework	Low, primarily focused on PBR and sharpening scrutiny of IRPs	Increased focus on DER coordination, utility as platform for two way distribution level trading, interconnection process, and non-wires solutions	Low, utilities directed to retain baseload resources in ratebase until end of useful life	High, places decarbonization mandate on utilities	High, requires unbundling, identification and recovery of stranded costs, creation of retail arrangements for small customers
Cost impact	Moderate decrease	Neutral and customer specific depending on ability to add DERs	Increase	Increase	Decrease depending on market conditions

11.3 Congruence of indicative paths with stated goals

Each of the above pathways differs in their objective function. Path 1 minimizes disruption to the sector. Path 2 facilitates technological change and small-scale entry. Path 3 emphasizes job

[352] Securitization could also be included in all of the other pathways as a means to accelerate evolution of the generation mix.

protection and use of traditional technologies. Path 4 focuses on addressing climate change. Finally, Path 5 targets technology neutral reductions in wholesale power costs. Figure 138 compares the five paths across multiple goals and provides an indicative ranking for each goal. The framework is illustrative, and intended as a thought exercise rather than a definitive categorization. While the rankings presume an equal weight, and allow for ties, policymakers may view some objectives as more important than others. Rankings should not be added across categories given that the relative distance between rankings within one category may differ from that in another.

Figure 138. Illustrative path rankings within criteria

Ranked item	Path 1	Path 2	Path 3	Path 4	Path 5
	Enhanced status quo	DER-centric	Baseload preservation	Aggressive decarbonization	Wholesale competition
Reliability	1	1.5	1.5	2	1
Affordability	2	2.5	3	4	1
Predictability	1	2	3	5	4
Accessibility	1	2	1	2	1
Space for new entry	5	2	5	3	1
Transition costs	1	3	2	5	5
Sector employment	4	3	1	2	5
Local tax base retention	3	2	1	1	4
Emissions reduction	4	3	5	1	2

It is important to note that in some areas the differences between the pathways are small, and can be addressed with good market and regulatory design. For example, with regards to ***reliability***, in all scenarios interconnected power sector actors are bound by NERC standards, and for those that are IURC jurisdictional, IURC performance requirements. While the DER-centric path increases complexity of utility system operations, reliability would likely not be compromised. Likewise, under an aggressive decarbonization scenario, although integration and backup of intermittent generation pose some reliability concerns, these can be managed within existing institutional structures.[353]

Affordability has two components: the total costs to be recovered from ratepayers, and the extent to which provisions are available to assist low income customers. Any of the five paths can be designed to provide support to those customers who need it. However, in terms of total costs to be recovered, the differences are wider; baseload preservation and aggressive decarbonization are likely to be more expensive (and possibly significantly so) than the enhanced status quo. DER-centric approaches may add costs as distribution level coordination of two-way power flows

[353] An argument can be made that the risk of generator bankruptcies increases under the wholesale competition path. However, LEI notes that generator bankruptcies would have little impact on reliability and on whether plants continue to run. Plants continue to run as long as variable operating costs and basic fixed costs are met, even if debt and equity is wiped out. The decision on whether plants continue to run is based on variable operating and basic fixed costs being met, irrespective of the financial health of the plant's owner. In addition, the potential for generator bankruptcy can be viewed as a healthy part of a working market, as it shows that investors, rather than ratepayers, are ultimately responsible for potential issues such as cost overruns.

requires additional controls, while properly designed wholesale competition regimes could reduce total costs to the sector.

Predictability is very much a matter of design. The status quo is familiar and the way in which rates change over time is well understood. Under a DER-centric approach this would not change, but additional investments may be required on the part of utilities to facilitate the transition, and these costs are not fully known. While baseload preservation simply retains existing assets within the existing cost of service framework, the challenge is that assets nearing end of life become less reliable, and do so at inconvenient times. This can increase the cost of replacement power while accelerating the timing of decommissioning. Although the pathway to aggressive decarbonization can include specified timelines, the pace of clean energy cost declines is unknown, particularly for aspects such as battery storage. While wholesale competition exposes more customers to price volatility, properly designed transitions provide protections to vulnerable consumers which can be linked to revenue management for otherwise stranded assets.

Accessibility – the ability of any customer to receive service if they want it – does not vary greatly across the pathways. In all cases, the distribution entity would retain an obligation to serve. However, not all customers have the ability to install DERs, and depending on the design, under aggressive decarbonization, customers may differ in their access to clean supply options.

The paths differ more widely when it comes to providing ***space for new entry***, which can also be seen as a proxy for innovation. The enhanced status quo and baseload preservation score poorly on this criteria, although in both if IRPs require issuing requests for proposals ("RFPs") to market test any proposed utility capacity replacement of expansion, some opportunities for non-utility investment would exist. Wholesale competition and DER-centric approaches offer the most potential for new entrants, though with different characteristics. The DER-centric approach favors smaller scale customer centric technologies, whereas wholesale competition would allow these but also larger scale entrants. Aggressive decarbonization would also provide opportunities for new entrants depending on whether the way it is achieved is through utilities issuing RFPs or through direct utility investment.

Transition costs (administrative and one-time analysis and implementation costs) are minimal under the enhanced status quo and baseload preservation paths, as each largely is based on current arrangements. The DER-centric approach can be managed over a period of time such that transition costs can be minimized. While Indiana benefits from being a member of existing ISOs and from being able to learn from the experience of other states with regards to wholesale competition, the process of quantifying stranded costs, determining recovery, and phasing in competition for small customers takes time and must be staffed.

None of the pathways specified is likely to decimate ***employment*** in the sector, which is in any case facing demographic challenges within its workforce due to an aging population. However, because large coal stations are significant employers, baseload preservation likely results in the highest level of employment. Aggressive decarbonization may partially replace employment lost at coal stations, and result in investment in higher capacity due to lower load factors, leading to

potentially more employment than the status quo.[354] The DER-centric approach would have a modest positive impact on employment relative to the status quo, as many small-scale facilities require little additional labor, though there may be some increase in staffing required to coordinate DERs. While wholesale competition can be expected to lead to some accelerated capacity retirements, there would be some potential substitution effects which would dampen declines.

The impact is similar with regards to ***local tax base retention***. Local includes county, townships, road districts, schools, municipalities, and other similar bodies. Baseload preservation likely retains the most taxable property as large scale coal plants remain in service longer. Aggressive decarbonization adds more new investment than any other pathway, and thus may be best for municipalities over the long run. The DER-centric path also involves adding investment but, depending on the nature of the equipment, may have little impact on municipal tax revenues. The enhanced status quo sees little change in local tax revenues, while wholesale competition, if it leads to accelerated retirements, may cause local tax revenues to fall.

Finally, when considering ***emissions reductions***, there is a wide divergence in impacts among the paths. Aggressive decarbonization by design is the most beneficial from an emissions reduction standpoint. However, DER-centric and wholesale competition both contribute to decarbonization by emphasizing investment in the most efficient new resources. The enhanced status quo makes little impact on expected levels of emissions, while baseload preservation has a negative impact unless emissions are matched with qualified offsets.

The efficacy of each path in achieving the stated goals in turn impacts potential support from various stakeholders. Figure 139 provides an illustration of how various stakeholders may respond to each path based on the weight they assign to the goals above.

[354] Per the Indiana University Public Policy Institute's ("IU PPI") August 2020 report titled "Economic, Fiscal, and Social Impacts of the Transition of Electricity Generation Resources in Indiana," the potential number of jobs per 100 MW of capacity could be: up to 32 for solar, 25 for wind, and 69 for coal. LEI notes that as solar and wind operate at lower capacity factors, two to three times as much replacement capacity may be needed, meaning the jobs impact may be similar. As noted in the IU PPI's report, coal-reliant communities have historically not been those that gain from renewable energy development, although there are steps that can be taken to maximize local benefits from an energy transition.

Figure 139. Indicative stakeholder views on various pathways

Stakeholder grouping	Path 1	Path 2	Path 3	Path 4	Path 5
	Enhanced status quo	DER-centric	Baseload preservation	Aggressive decarbonization	Wholesale competition
Utilities	3	5	1	2	4
IPPs	4	3	5	2	1
DER developers	4	1	5	3	2
Unions	3	4	1	2	5
Local fuel suppliers	2	3	1	5	5
Industrial consumers	3	2	5	4	1
Environmental advocates	4	2	5	1	3
Small customer advocates	1	2	5	4	3

Utilities are most likely to support those options which place least pressure on their existing monopolies. Baseload preservation and aggressive decarbonization both present opportunities to retain or increase ratebase. The enhanced status quo has a neutral impact, while both DER-centric and wholesale competition potentially reduce the role of the utility. In some ways, the DER-centric model is more threatening because it could reduce the need for both large scale generation and for wires investments, though utility investment in coordination would be required.

IPPs and DER developers are likely to favor wholesale competition (if long term contracts linked to utility IRPs are not available) and the DER-centric model, respectively. Both may also see opportunities in aggressive decarbonization depending on how procurements and incentives are structured. Baseload preservation is worst for each, as retention of existing generation crowds out opportunities for new investment. By contrast, ***unions*** are likely to see wholesale competition and DER-centric models as the biggest threats to their members, given that unions are less prevalent at IPPs, and DER investment has minimal impact on employment. Baseload preservation also preserves existing union jobs, and unions would likely lobby for union protections in any aggressive decarbonization procurements.

Local fuel suppliers strongly support baseload preservation; the enhanced status quo may have some benefits if it prevents new entrants. Local fuel suppliers are not likely to feel threatened greatly by the DER-centric approach given its focus on smaller scale resources. But because wholesale competition would likely favor gas-fired resources, and aggressive decarbonization could lead to elimination of inflexible fossil plants, local fuel suppliers would oppose these pathways.

Industrial consumers are a heterogenous group, but are presumed to be focused on achieving a balance between cost and reliability. Flexibility is also important for industrial consumers, along with reducing barriers to cogeneration. This suggests that well designed competitive wholesale markets would be a favored path for some. A DER-centric approach may also garner support given the additional opportunities it would bring for optimization of on-site generation. While industrial consumers would likely support enhancement of the status quo, support would be lukewarm. Because both baseload preservation and aggressive decarbonization would likely increase costs, industrial support would be limited. However, for industrial consumers with explicit environmental, social, and governance ("ESG") mandates, there may be some support

for, if not aggressive decarbonization, some means of allowing them to claim carbon neutrality through green energy programs or the purchase of offsets.

While ***environmental advocates*** would join with industrial consumers in opposing baseload preservation, aggressive decarbonization would likely be their favored outcome. A DER-centric approach focused on renewables would also find favor. Because wholesale markets promote efficient use of scarce resources, environmental groups may not oppose such a transition, especially if it were to include an explicit cost for carbon. Environmentalists would likely be neutral to the enhanced status quo, but would warm to it if any form of PBR included explicit incentives related to environmental performance.

Like industrial consumers, ***small customer advocates*** are presumed to be focused on cost and reliability. This leads to similar skepticism regarding baseload preservation and aggressive decarbonization; while small customers may be interested in environmental improvements, willingness to pay may be capped. Unlike industrial consumers, however, small customer advocates would likely be skeptical of wholesale competition due to perceptions of volatility, even though market designs can be put in place to help small customers manage this risk. The enhanced status quo is the most familiar set of arrangements and thus likely most attractive for small customer advocates, though they may not oppose the DER-centric model provided it does not result in cross-subsidies.

Viewed holistically across evaluative criteria and likely stakeholder views, there appears to be reasonable justification for the DER-centric approach. However, adopting this approach need not prevent exploring ways to attain the benefits of wholesale competition if transition costs can be managed. Furthermore, the DER-centric approach can be developed in a fashion that provides incremental environmental benefits relative to the status quo. Indiana should seriously consider PBR, make sure IRPs are technology and ownership neutral, incorporate pathways for DER innovation, reduce the exclusive role of the utilities while respecting the need to recover verified stranded costs, and explore ways of gradually introducing wholesale competition while protecting small consumers. Where possible, evolution of the electricity sector in Indiana should be pursued through IURC-sponsored processes, rather than dictated through legislation. Legislation can set forth broad guidelines, such as identifying the objective function and evaluative criteria, but the details should be left to the IURC proceedings so as to facilitate a fulsome record and broad stakeholder participation.

12 Concluding remarks and recommendations

Despite increases in rates over the past decade, Indiana retains a number of strengths. Furthermore, peer states are also facing upward pressure on rates. To avoid rates increasing more than is necessary, Indiana should adopt a set of principles to guide future policy, and it should engage in an in-depth review of rate design.

12.1 Indiana's strengths

Indiana's strengths include its centrality in US transportation systems, its overall resource potential, in-state analytical capabilities, and a responsive regulatory regime.

12.1.1 Crossroads of networks

Indiana benefits from being in the center of a dense set of rail, road, pipeline, and electric transmission networks. This contributes both to price stability and reliability. Unlike New York or New England, which sit at the end of increasingly congested pipeline infrastructure, Indiana has access to multiple supply basins and faces smaller basis differentials (see Figure 140). Likewise, membership in MISO (for most of the state) and PJM (for Northern regions) gives Indiana consumers access (albeit indirect in the absence of unbundled markets) to the largest ISOs in the US. For instance, on average, MISO and PJM's operating capacity (MW) over the past three years is five times as large as NYISO and ISO-NE's (see Figure 141). While Illinois and Ohio enjoy similar advantages, access to wide networks provides a high degree of policy optionality, particularly with regards to load balancing, along with the ability to export surpluses.

Figure 140. Gas hubs price basis differential comparison (2017-2019)

	2017	2018	2019
Chicago vs MichCon citygate (Indiana)	0.9%	0.7%	1.9%
Average basis differential between NYISO and ISO-NE	24%	12%	18%

Note: LEI used the Chicago Citygate and MichCon Citygate gas hubs for Indiana; LEI used TETCO M3, Transco Z6 Non-NY, and Iroquois Z 2 for New York ISO and Algonquin Citygate for New England ISO.

Source: Third party database provider

Figure 141. Historical operating capacity (MW) in selected RTO/ISOs (2017-2019)

	2017	2018	2019
MISO	191,452	189,658	189,558
PJM	204,402	213,100	209,980
NYISO	44,395	45,461	45,592
ISO-NE	35,626	38,012	38,679

Source: Third party database provider

12.1.2 Conventional and renewable resource potential

Indiana's ability to rely on in-state resources, whether conventional or renewable, gives policymakers flexibility in considering the future resource mix. Indiana has available land and reasonably attractive potential wind speeds; it also produces a portion of the fossil fuels it consumes. This means that while focusing on least cost outcomes in the electricity sector, there is a reasonable prospect that there will be benefits to the broader Indiana economy further up the value chain.

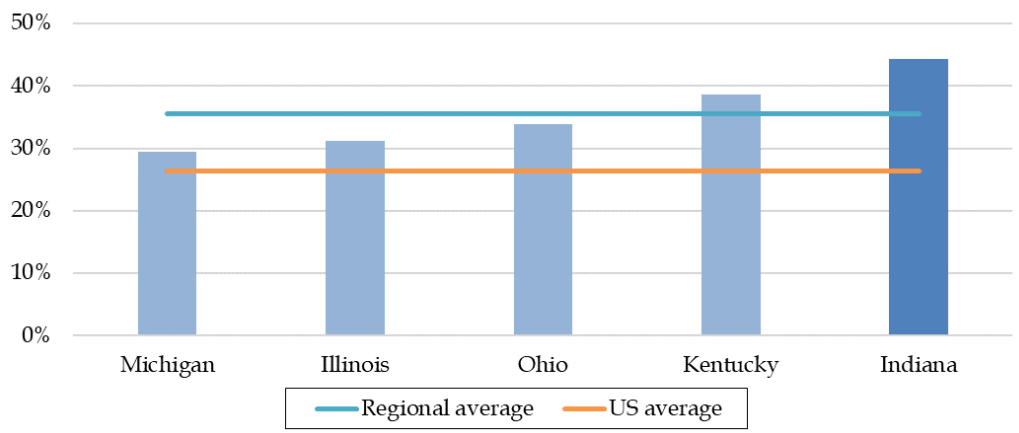
12.1.3 Significant analytical capabilities

The state has access to significant analytical capabilities at SUFG and has shown an inclination to study various electricity sector matters *before* making a policy decision; not all states and provinces have this discipline. The academic nature of SUFG provides for a degree of independence and objectivity, which is critical to making sound policy.

12.1.4 High proportion of industrial load

The relatively high proportion of industrial load in Indiana can increase options available to policymakers due to the volumes and load shapes involved. As shown in Figure 142, Indiana has a higher proportion of industrial load relative to its neighbors. While industrial load can pose risks to utilities if load is overly concentrated on one customer or industry and challenges arise for that sector, industrial load contributes to economies of scale, may help to manage peak, and can provide a foundation for exploring new market and regulatory arrangements without burdening other customer classes.

Figure 142. 2019 share of industrial load to total load in the region



Source: EIA 861

12.1.5 Challenges in other states

While rate increases over the past decade in Indiana have changed its relative position among its peers, the forces pushing rates higher in Indiana are not unique. The change in relative status

may be partly a matter of timing. Illinois and Ohio both face challenges with regards to whether to mandate ratepayer support for aging nuclear stations, and Ohio has also provided support for struggling coal plants. Green energy ambitions in Illinois, and to a certain extent Michigan, are likely to place upward pressure on rates in those states, particularly as environmental aspirations are not always consistent with current engineering realities. In some cases, neighboring states have significantly older infrastructure (for example, Chicago's natural gas distribution system) that require costly upgrades. It is reasonable to assume that depending on the evolution of the power sector in peer states, rates in some states may begin to rise at a rate faster than Indiana's.

12.2 Recommendations going forward

The recommendations below should be the foundation of policy design in Indiana. While the recommendations are focused on how to make policy, rather than what the policy should be, if properly applied, they should facilitate development of long run, least cost policies consistent with stated objectives.

12.2.1 Clearly define objective function

Electricity policy design is an exercise in constrained optimization. Historically, the objective has been provision of electricity service at long run least cost, consistent with reliability expectations and a fair allocation of costs. As environmental sensitivity increases, emissions objectives are in some states increasingly part of this equation. Some jurisdictions also see the sector as an element of industrial policy, either with regards to rate levels or by identifying preferred technologies. While good policy can take into account all of these factors, it is critical that the objective be specific, and the means of measuring progress towards it be as objective as possible.

12.2.2 Technology and ownership neutral

Presuming that the electricity sector is not seen as part of a larger industrial strategy, policymakers should, as much as possible, seek to be technology and ownership neutral. Utilities can retain a valuable function coordinating assets even if they don't own them; extending RFPs from generation down to exploring non-wires alternatives for grid expansion can help reduce costs and allows for creative solutions. In some cases, services the utility formerly provided in-house using capital may be obtained externally through services contracts; the classic example of this is comparing owning a server to leasing cloud computing services. This doesn't mean that the utility won't sometimes be the lowest cost solution, but greater market testing of utility proposed investments can lead to a more dynamic sector.

Technology neutrality is also important as a means to meeting environmental objectives at least cost. Instead of simply pricing emissions or creating a single category REC for zero emitting resources, almost all states have had a plethora of REC and procurement programs targeted at specific technologies. Northeastern states are vying with one another to engage in costly offshore wind promotion, when a range of cheaper onshore renewables may be available. If the objective is truly to maximize environmental benefits at least cost, then picking specific technologies undermines that objective as it ossifies the program to only those eligible technologies, may unfairly distinguish between new and existing resources despite those resources having similar

emissions characteristics, and does not allow for automatic reallocation among resource types as relative costs change. Using some form of carbon pricing, such as joining RGGI or imposing a carbon tax (with proceeds refunded to Indiana tax payers), would allow Indiana to pursue environmental objectives without "picking winners" and would also allow for carbon capture and storage alternatives. Such initiatives, if undertaken, should also be designed to be compatible with future Federal carbon pricing efforts should they arise. Regardless, if emissions reduction programs are deployed, they should be designed to keep the levelized cost of carbon abatement in mind.[355]

12.2.3 Avoid trying to accomplish public policy goals through electricity rates

Traditionally, electricity bills were viewed as difficult to avoid and thus became a vehicle for funding a range of public policy goals, ranging from energy efficiency to support to low income households, to name only a few. However, as technology evolves and customers have an increasing ability to reduce load, if not yet able to comfortably abandon the grid entirely, the rationale for using the electric bill to fund other programs wanes. If riders associated with public policy costs cause total bills to reach a level where grid defection becomes feasible, it is not only the various public programs that will receive less funding, but costs for the electricity sector itself will be spread across a smaller base. Public policy riders could accelerate customer load reductions in a way that would otherwise not be economic and need to be carefully considered before being imposed.

Electricity bills are often an inefficient way to provide support for public policy objectives; if the concern is about employee layoffs due to the closure of an uneconomic plant, it is usually cheaper to provide direct income support to the employees than it is to keep an uneconomic plant running. Similarly, support for low income households may be best pursued through social welfare schemes rather than discounted electricity rates.

12.2.4 Recognize importance of optionality

Electricity system designers are accustomed to focusing on large scale investments recovered over several decades, in some cases 40 years or more. But the pace of technological change and the rapid declines in price for some resources increases the risk that new long-lived large-scale assets will be stranded. In some cases, a smaller, shorter term investment, even if more expensive on an amortized basis, may be more prudent based on where future costs are likely to be at the time of replacement. Furthermore, uncertainty with regards to load make building to meet future load growth riskier than it was in the past. Incorporating the value of optionality into capital decisions will help to protect ratepayers and should be encouraged.

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[355] Columbia Center on Global Energy Policy. *Levelized Cost of Carbon Abatement: An Improved Cost-assessment Methodology for a Net-zero Emissions World.* October 2020.

12.2.5 No necessity to be a first mover

While costs have been rising in Indiana, the state has avoided some of the more costly programs pursued by other states. New York's Reforming the Energy Vision ("REV") initiative is an example of an innovative but costly program that other states can learn from. Similarly, states with aggressive renewables mandates are beginning to reach saturation points, beyond which further additions lead to excess power in some parts of the year and insufficient capacity back-up in others. It is unclear how electricity policy in Illinois is going to evolve, but there are prospects of programs there that may increase costs to consumers without efficiently meeting stated goals. Indiana does not need to be a pioneer in any of the envisioned pathways for evolution; each has been attempted elsewhere and experience in other jurisdictions can be mined to improve outcomes in Indiana.

12.2.6 Acknowledge that DERs will provide a form of competition regardless of whether market is unbundled

Contrary to the hype they sometimes receive, DERs are not yet ubiquitous, and traditional utilities are not on the cusp of being supplanted. However, even if Indiana chose not to extend access to competitive wholesale generation markets to all customers, DERs are a form of competition for incumbent utilities. As DER costs fall and opportunities for coordinating DERs increase, the cost of DERs will become an effective price cap on what utilities can charge, even if their formal approved rate sheets say they can charge more. Competitive wholesale markets developed because cheap combined cycle gas turbines became readily available and provided opportunities for large loads to save money, relative to the rates they were charged by their utility.

While DERs are more expensive than large scale generators on a levelized basis, they compete at a different point in the value chain. Because DERs substitute for delivered power, instead of wholesale power, the value of the avoided distribution charge is a significant consideration. As more DERs are installed, it will be critical to ensure that cross subsidization is minimized, and that distribution utilities and ISOs are able to monitor their impact on the system. Even if Indiana chooses not to pursue a DER-centric path, some regulatory changes are likely to be necessary as DERs increase in response to other stimuli.

12.2.7 Consider reassessing reliability and who pays for it

Currently, most North American utilities plan based on a 1 hour in 10,000 standard for outages. This standard drives estimated reserve margins and the design of all elements of the system. However, this "one size fits all" definition of reliability may be providing greater reliability than some customers need, while not meeting the needs of others. Improvements in metering, telecommunications, electricity using equipment, and markets increasingly allow for differentiated reliability, where customers can choose whether they can withstand more outages in return for a credit, or whether they need special additional services consistent with their industrial processes. As batteries become cheaper and are incorporated into more devices, customer ability to sustain brief outages with minimal loss of welfare increases. Regulators need to consider, and regularly assess, whether reliability standards are consistent with current

realities, and determine whether they should be increased or decreased, and whether mechanisms can be developed to allow customers to reveal their reliability preferences.

12.2.8 Detailed review of rate design is necessary

A more complicated regulatory framework is not necessarily a better one. Nonetheless, the challenges with traditional cost of service regulation, particularly incentives to over-capitalize, mean that alternative rate regimes need to be explored. US states in general have less sophisticated incentive regimes than those found in Europe, and in turn Indiana's regime appears to have fewer mechanisms designed to align interests of utilities and ratepayers than do regimes in other US states. A properly designed PBR arrangement can help hold utility rate increases to less than inflation. Periodically exploring whether additional efficiency incentives and performance standards would benefit customers is an important step in assuring rates are just and reasonable.

12.2.9 Avoid sudden movements

Lastly, most policy failures are the result of hasty changes implemented with insufficient analysis. Sudden policy changes, regardless of their objective, often do more harm than good. Measures to cap prices or restrict access in response to some short-term phenomenon, if not implemented on a limited and short-term basis, almost always have unintended consequences. Well-designed processes require consultation, investigation, preparation, and iteration.

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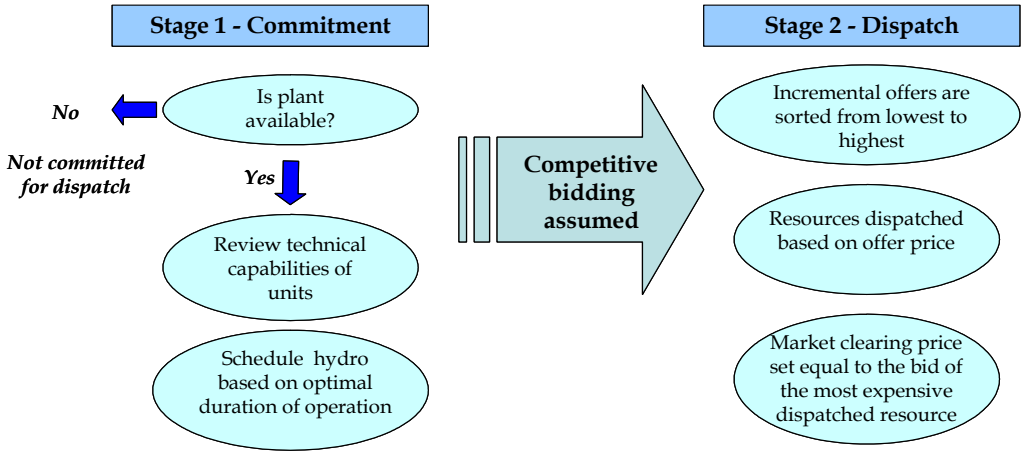
14 Appendix B: Overview of forecasting methodology

14.1 How POOLMod works

For the wholesale energy prices outlook, we employed our proprietary simulation model, POOLMod, as the foundation for our electricity price forecast. POOLMod simulates the dispatch of generating resources in the market subject to least-cost dispatch principles to meet projected hourly load and technical assumptions on generation operating capacity and availability of transmission.

POOLMod consists of a number of key algorithms, such as maintenance scheduling, assignment of stochastic forced outages, hydro shadow pricing, commitment, and dispatch. The first stage of analysis requires the development of an availability schedule for system resources. First, POOLMod determines a 'near optimal' maintenance schedule on an annual basis, accounting for the need to preserve regional reserve margins across the year and a reasonable baseload, mid-merit, and peaking capacity mix. Then, POOLMod allocates forced (unplanned) outages randomly across the year based on the forced outage rate specified for each resource.

Figure 143. POOLMod's two-stage process



POOLMod next commits and dispatches plants on a daily basis. Commitment is based on the schedule of available plants net of maintenance and takes into consideration the technical requirements of the units (such as start/stop capabilities, start costs (if any), and minimum on and off times). During the commitment procedure, hydro resources are scheduled according to the optimal duration of operation on the scheduled day. They are then given a shadow price just below the commitment price of the resource that would otherwise operate at that same schedule (i.e., the resource they are displacing).

Also, POOLMod is a transportation-based model, giving it the ability to take into account thermal limits on the transmission network.

14.2 Modeling assumptions used in the wholesale energy forecasts

Parameters	Assumptions used
Market topology	LEI modeled three sub-regions (MISO West, MISO Central, and MISO South) based on historical transmission constraints. Indiana is located in MISO Central. For PJM, LEI modeled PJM into 10 zones. Indiana is in PJM's AEP zone.
Demand	Demand consists of hourly load data for the duration of the analysis period. LEI's peak demand and total energy forecast is developed directly from MISO's Future II (middle case) scenario of MISO's MTEP 21 Whitepaper issued on April 27, 2020 and PJM's 2020 Load Forecast Report. Over the next ten years (2021-2030), Indiana's peak demand is forecast in the 20,159 MW to 21,984 MW range, with an average peak demand of 20,919 MW. In terms of total energy consumption, Indiana is expected to consume between 125,124 GWh and 141,127 GWh from 2021 to 2040. Average energy consumption is projected to be 132,820 GWh in the ten-year timeframe.
Supply (new entry)	LEI assumed that generators make economically rational capacity investment decisions timed to load growth and earnings potential across the wholesale electricity markets. The new renewable capacity additions reflect major utilities' commitment in their IRPs and compliance with RPS requirements. LEI also factored in the carbon emission goals and renewable penetration target stated in MTEP 21 Future II scenario to determine the new capacity addition mix.
Supply (retirements)	LEI scheduled plant retirements based on three major approaches: 1) RTO and utilities' announcements or IRPs; 2) age-based retirement suggested by MISO Future II (36 years for coal, 45 years for gas-CC, and 36 years for gas-other; and 3) an economic analysis to remove fossil-fueled plants subject to retirement risk upon compliance with environmental regulations.
Fuel prices	Gas: for the near term, LEI relied on the forwards market for projecting delivered gas prices for the years in which forwards are liquid. LEI used the three-month average forwards for the modeled 2020 and 2021 delivered gas price, as reported by OTC Global Holdings. From 2022 onwards, the delivered gas price is based on fundamentals analysis, using a reference point plus a transportation adder. LEI employed its proprietary gas Levelized Cost of Pipeline ("LCOP") model to forecast longer-term gas price trends. For MISO Central, LEI used the average price of Chicago Citygates Hub and

	Michigan Consolidated Citygates Hub ("MichCon"). For PJM, LEI used the MichCon Citygates. From 2021 to 2030, the projected gas prices at MichCon Citygates fall in the range between $2.32/MMBtu and $3.75/MMBtu, and average $3.03/MMBtu per year (note prices are in nominal dollars). At Chicago Citygates Hub, the gas prices are estimated to range from $2.40/MMBtu to $3.81/MMBtu, with an average of $3.10/MMBtu per year over the next ten years. Oil: Distillate oil price forecasts were based on the NYMEX heating oil price forwards in the short-turn (years 2021 and 2022). In the mid to long term (beyond the horizon of NYMEX forwards), oil commodity index prices were escalated based on implied projected growth rates for crude oil from EIA's AEO 2020. Coal: Coal is dominant fuel in many regions of MISO. Plant-specific coal prices outlooks were used given the diversity in coal sourcing, quality, transportation, price, and sulfur content levels. Coal price assumptions are based on 2018 average delivered price at each plant escalated in nominal terms using the annual rate of change implied in the coal price index and inflation rate from EIA's AEO 2020.
Emissions	The Cross-State Air Pollution Rule ("CSAPR") took effect starting January 1st, 2015 for SO2 and annual NOx reductions and May 1st, 2015 for ozone season NOx reductions. SO2 and NOx forecast allowance prices are based on SNL for the short term and escalated at 2% inflation over the long term. The projected SO2 emission allowance prices range from $2.4/ton in 2021 to $2.9/ton in 2030; the forecast NOx emission prices range from $2.9/ton in 2021 to $3.5/ton in 2030. To model cost adders that would reflect the expense needed to attain CSAPR compliance, we first examined each thermal plant's reported historical SO2 and NOx emission rates and the amount of allocated allowances. When a plant's annual emissions exceed the amount of allocated allowances, we analyzed the cost of purchasing allowances versus installing emission control equipment. Where purchasing allowances proved cost-effective, allowance costs were added to variable O&M costs. If installing emissions control equipment proved less costly on a net present value basis, a retrofit expenditure was considered for the plant, increasing its minimum going-forward fixed cost and affecting the default bid levels in the capacity market.
Imports/Exports	MISO has mainly been a net importer of energy from its neighboring markets in recent years. In LEI's modeling, net imports are modeled based on MISO's historical Net Scheduled Interchange ("NSI") for the most recent years

available (2016-2018) for all interties, except flows between MISO and Ontario, and flows between MISO and PJM.

Assumptions on interchange flows between MISO and PJM are based on PJM's Interchange Summary Report, while we rely on the Ontario Independent Electric System Operator's data for defining energy flows between MISO and Ontario. The purpose of this is to remain consistent in the data used across market forecasts for different regions published by LEI.

15 Appendix C: About London Economics International LLC

LEI is a global economic, financial, and strategic advisory professional services firm specializing in energy and infrastructure. The firm combines a detailed understanding of specific network and commodity industries, such as electricity generation and distribution, with sophisticated analysis and a suite of proprietary quantitative models to produce reliable and comprehensible results. The firm's roots stem from the initial round of privatization of electricity, gas, and water companies in the UK in the late 1980s. Since then, LEI has advised private sector clients, market institutions, and government on policy initiatives, market and tariff design, asset valuation, market power, and strategy in virtually all deregulated markets worldwide.

The following attributes make LEI unique:

- ***clear, readable deliverables*** grounded in substantial topical and quantitative evidence;
- ***extensive experience in regulatory filings*** provides expertise to advise on network tariffs and design rates under PBR;
- ***wealth of knowledge of energy and infrastructure regulation*** worldwide to provide expert testimony services on regulatory best practices and innovation;
- ***balance of private sector and governmental clients*** enables us to advise both regarding the impact of regulatory initiatives on private investment and the extent of possible regulatory responses to individual firm actions;
- ***Boston-based firm*** with in-depth knowledge of energy policies and regional issues; and
- ***worldwide experience*** backed by multilingual and multicultural staff.

In the following subsections, we showcase a sample of projects highlighting our broad experience relevant to the Study. LEI staff have completed several engagements that have advised numerous industry associations, state governments, regulators, and private entities on the energy issues discussed throughout this report. Specifically, we have divided our project qualifications into the following categories: engagements centered around rate structuring, rate design, and regulatory models; and experience in Indiana and the Midwest region.

15.1 Rate structuring, design, and regulatory models

For several clients across the electricity supply chain, LEI has assessed and completed engagements related to electricity rate structures and their design. LEI has also completed numerous evaluations of utility regulatory models for state governments, agencies, and regulators across the US and around the world.

- ***Study of retail rates and options to increase regional competitiveness:*** LEI was selected by the Kansas Legislative Coordinating Council to perform a study of the retail rates of Kansas electric public utilities. The study, which involved two main sections, aimed to inform electric

sector policies and result in competitive electric rates and reliable electric service in Kansas. Section 1 of the study evaluated the effectiveness of current Kansas ratemaking practices and their ability to attract required capital investments and balance utility profits with public interest objectives and reliable service. Section 2 focused on exploring options available to the State Corporation Commission and the Kansas Legislature to affect Kansas retail electricity prices to become regionally competitive while providing the best practicable combination of price, quality and service.

- ***Study of rates and rate design for an industry association:*** LEI was engaged to prepare an Industrial Electricity Rate Economic Impact Study in Ontario's manufacturing sector. The scope of work consisted of review of current Ontario industrial electricity rates and rate designs; assessment of competitive electricity rate levels through a comparison with comparable US jurisdictions; development of options to change rates in a manner consistent with rate setting principles that are beneficial to industrial consumers and the province; quantification of economic benefits from appropriate rate adjustments; and consultation with relevant industry and government officials and experts throughout the project.
- ***Review of ownership and regulatory models:*** LEI provided a study to assess options for transforming the ownership and regulatory model used to govern the electricity sector in Hawaii. This was a large, significant initiative to provide the government of Hawaii with independent and objective research and analysis to help it scope out the most appropriate course of action in achieving Hawaii's overarching policy goals. There were four main phases to this work: 1 and 2) to determine the long-term operational and financial costs and benefits of electric (i) utility ownership models, and (ii) utility regulatory models, to serve each county of the State of Hawaii; 3) to provide additional insight and analysis of ownership and regulatory model changes; and 4) to provide for the development and delivery of the executive summary, formal presentation and final report in a format approved by the client.
- ***Review of regulatory and tariff structures for power utility regulator:*** LEI was retained by a power utility regulator in Kentucky to review regulatory policies and tariff structures to determine how they can be altered to elicit demand reductions and renewables implementation. The engagement included stakeholder interviews to solicit feedback from all relevant stakeholder groups on the necessary updates to the planning and approval process to meet a legislative mandate to increase the use of renewable resources and reduce demand. The review process consisted of analyzing the current processes for renewable and distributed generation and demand-side management programs and proposing recommendations to improve the efficacy of these programs.
- ***Review of tariff-setting regimes for Canadian regulator***: For a Canadian regulator, LEI prepared a white paper on the comparative advantages and drawbacks of various tariff-setting regimes, from performance-based regimes to cost-of-service. This project involved a general overview of tariff-setting practices across Canadian provinces as well as highly detailed Canadian and international case studies and an examination of the key lessons to be learned from each case. Detailed case studies covered the tariff-setting regimes in place in the UK, the Australian National Electricity Market, and the Netherlands. As part of its deliverables, two workshops were conducted with a variety of regulators and utilities.

- ***Electricity regulation in Newfoundland and Labrador:*** LEI was engaged by the Commission of Inquiry Respecting the Muskrat Falls Project to serve as an expert to the Inquiry. LEI's scope of work consisted of preparing a report addressing the following topics: a comparison of Newfoundland and Labrador's electricity regulation system relative to other Canadian jurisdictions; assessing the system's ability to deal with challenges stemming from interconnection, including energy marketing; exploring the province's energy policy; recommending changes to the province's electricity pricing model; and assessing the potential role for renewable energy generation expansion.
- ***Review of rates across Canada:*** For a Canadian industry association, LEI conducted a study that consisted of: a review of delivered costs of electricity (broken down by component) across all Canadian provinces over a 5-year historical period for residential, commercial, and industrial customers; a qualitative assessment describing the reasons for rate differentials across provinces; and a forecast for the delivered cost of electricity in Alberta (including forecasts for energy, transmission, and distribution) under various scenarios and for different rate classes over a 15-year forward period.
- ***Way forward for regulation in Ontario:*** LEI was retained by the Ontario Energy Board to assist in developing regulatory reforms with respect to utility remuneration to support the evolution of the sector. As part of this engagement, the LEI team prepared a concept paper on approaches to utility remuneration and incentives, and attended and presented at stakeholder and industry events.

15.2 Regional experience

LEI staff have a deep understanding of the electricity sector dynamics and markets in Indiana and the Midwest as a result of having completed numerous engagements in the region over the past two decades. A sample of some recent projects are highlighted below.

- ***Midwest market primer:*** LEI conducted a comprehensive review and analysis of the Midwest market, which involved analysis of the region's regulatory environment (including state-by-state assessments), the wholesale generation market, supply-demand balances, congestion issues, new planned additions, environmental compliance requirements, fuel price forecasts, and review of MISO's functions.
- ***Expert testimony regarding entry into MISO:*** LEI was engaged on the behalf of a public utility to provide evaluation services pertaining to the announced decision by Entergy to join MISO. LEI used a multi-disciplinary approach to perform a quantitative and qualitative analysis of specific costs/benefits attributable to Entergy and its customers following membership in either MISO or SPP, including but not limited to net trade benefits, transmission cost allocation, governance issues, and continued participation in the Entergy Service Agreement following RTO membership.
- ***Analysis on the economic opportunities for battery storage technology:*** LEI was engaged to conduct research into MidAmerican's plans to develop new renewable power projects and summarize findings with a specific value proposition to MidAmerican demonstrating how a battery will complement MidAmerican's development pipeline. Also, LEI performed series of sensitivities to identify the best market and market conditions that would maximize the

battery's revenues. Final deliverables included a series of electricity briefing papers discussing the outlook of natural gas markets and going-forward impact on electricity prices; market primer on Day-Ahead and Real-Time markets; and overview of renewable policies in the US.

- ***SOO Green Transmission Project:*** LEI was hired by SOO Green to conduct an independent rigorous modeling exercise to determine the potential revenues for a proposed transmission project wheeling power from Western to East MISO (and eventually PJM). LEI evaluated the revenue opportunities to the investors (e.g., private benefits of the line based on market price differences and the market value of the transmission) as well as social benefits to the MISO system (i.e., wholesale price reductions and capacity market price differences); and evaluated the incremental value of the business strategy of selling the energy (and capacity) out of East MISO to third parties who will serve customers ultimately in PJM. LEI's modeling exercise entailed evaluating intrinsic revenues (originating from power markets), extrinsic revenue (originating from price volatility), along with the green value of the Project (originating from the purchase of low-cost renewable energy).