THE LEVELIZED COST OF ELECTRICITY IN INDIANA

Isaac Orr and Mitch Rolling
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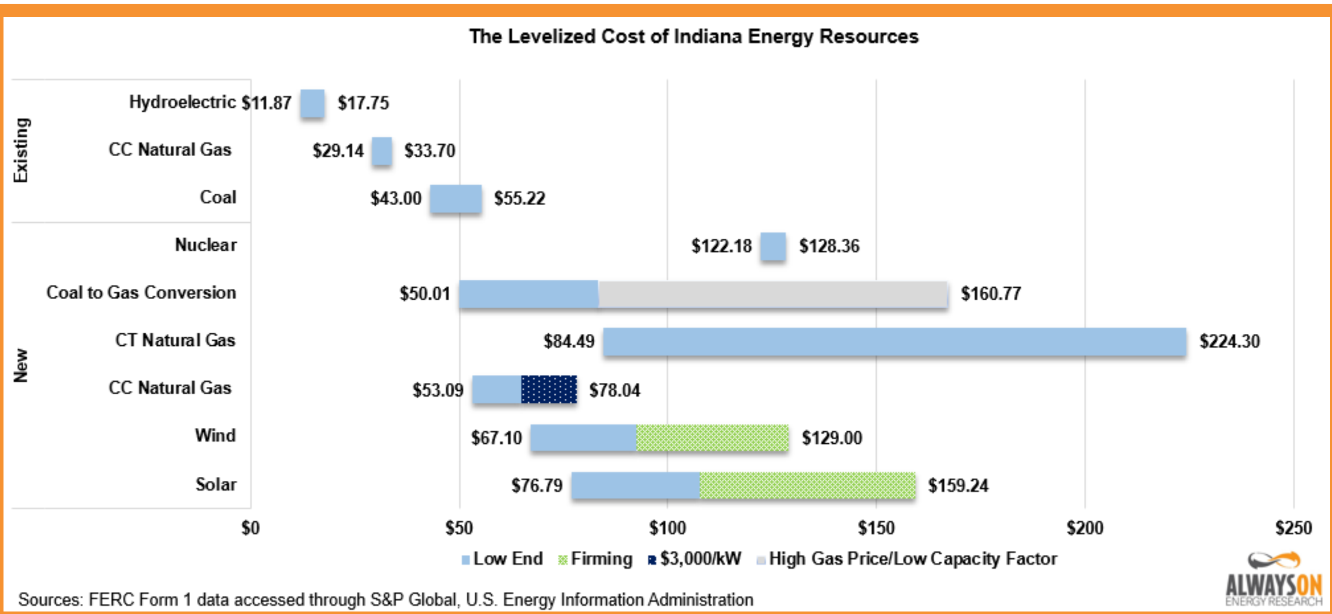


EXECUTIVE SUMMARY

- Always On Energy Research (AOER) conducted an Indiana-specific Levelized Cost of Energy (LCOE) analysis to determine the lowest-cost means of serving existing residential, commercial, and industrial customers and meeting anticipated electricity demand growth from data centers.
- Our modeling determined that the continued utilization of Indiana's existing hydroelectric, $17.75 per megawatt-hour (MWh), combined-cycle (CC) natural gas, $29.14 per MWh, and coal plants, $55.22 per MWh, while building new CC natural gas units, would be the most cost-effective means of serving existing customers and meeting incremental electricity demand ($53.09 to $78.04 per MWh).
- New wind, solar, and nuclear power plants would be significantly more expensive than other resources, with unsubsidized costs of $67.10, $76.79, and $122.18 per MWh, respectively.
- Wind and solar costs increase to $129 and $159.24 per MWh, respectively, when the cost of backup generation resources needed when the wind is not blowing, and the sun is not shining, are incorporated into their LCOEs.
- Continuing to use the state's existing natural gas and coal plants, while adding new combined-cycle natural gas power plants, is the fastest way to meet Indiana's growing energy requirements at the lowest cost to consumers and bolster reliability in the region.

FIGURE 1: YEARLY INCREASE IN INDIANA ALL-SECTORS ELECTRICITY PRICES VS THE U.S. AVERAGE

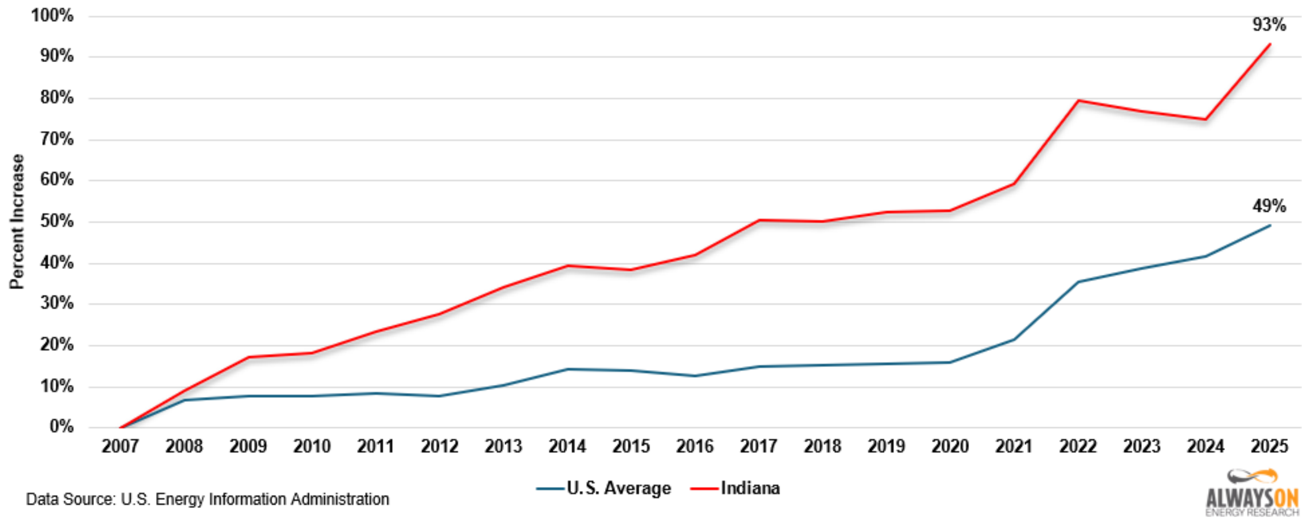


Figure 1. Indiana experienced a 93 percent increase in electricity prices from 2007 through 2025, a rate nearly twice the national average.

AFFORDABILITY, RELIABILITY, AND DEMAND GROWTH

Electricity affordability and reliability are growing concerns for Indiana families and businesses. Prices are rising, and regional grid operators warn of the threat of electricity shortages amid the retirement of reliable power plants and rising demand from data centers.

Between 2007 and 2025, Indiana's electricity prices rose by 93 percent, nearly twice the national average during this period (see Figure 1).[1] Prior to these dramatic cost increases, electricity prices in Indiana were 29 percent below the national average in 2007, but by the end of 2025, they were only 8 percent below the national average, eroding much of the state's cost advantage for energy-intensive manufacturers and imposing additional costs on families.

Reliability is also a growing concern in the state. The North American Electric Reliability Corporation (NERC) warns that Indiana's power grids face high risks of blackouts in the coming years if reliable power plants, mainly coal generators, are retired and data centers drastically increase electricity demand on the two regional grids that serve Indiana, the Midcontinent Independent System Operator (MISO), and Pennsylvania New Jersey Maryland (PJM) (see Figure 2).[2]

1 U.S. Energy Information Administration, "Average Retail Price of Electricity, All Sectors, Annual, Indexed to 2007 as a Percent," Electricity Data Browser, Accessed December 24, 2025, https://www.eia.gov/electricity/data/browser/#/topic/7?agg=1,0&geo=g0008&endsec=g&linechart=ELEC.PRICE.US-ALL.A~ELEC.PRICE.IN-ALL.A&columnchart=ELEC.PRICE.US-ALL.A&map=ELEC.PRICE.US-ALL.A&freq=A&start=2007&end=2024&chartindexed=1&ctype=linechart&ltype=pin&rtype=s&maptype=0&rse=0&pin=.

2 North American Electric Reliability Corporation, "Long Term Reliability Assessment 2025," January 2026, https://www.nerc.com/globalassets/our-work/assessments/nerc_ltra_2025.pdf.

FIGURE 2: RISK AREA SUMMARY 2026-2030

(Shows highest risk classification in the first years and states initial year of occurrence)

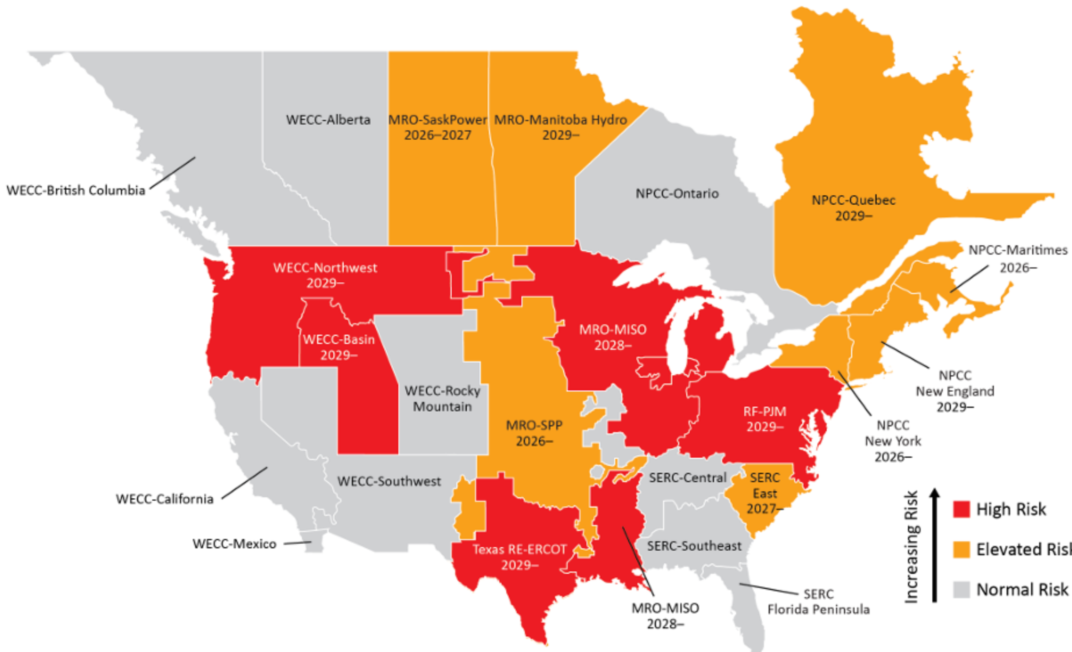


Figure 2. MISO and PJM face high reliability risks in the coming years due to factors including retiring thermal capacity, strong demand growth, and the intermittent nature of replacement capacity.

The shortage of reliable capacity is demonstrated by rising prices in the MISO and PJM capacity markets, where MISO prices increased from $30/megawatt (MW)-day for summer capacity in the 2024/25 planning year to $666.50/MW-day for summer capacity in the 2025/26 planning year.[3] In PJM, prices increased from $28/MW-day in the 2024/25 planning year to $333.44/MW-day in the 2026/27 planning year.[4]

Rising capacity prices have heightened scrutiny of proposed data center projects, which consume large amounts of electricity.

Data center demand growth in Indiana is expected to be significant, with an estimated 5,397 megawatts (MW) under construction and an additional 7,187 MW of proposed projects.[5] For context, the 5,397 MW of projects currently under construction exceed the maximum electricity demand of every Indiana utility except Duke Energy (see Figure 3).[6]

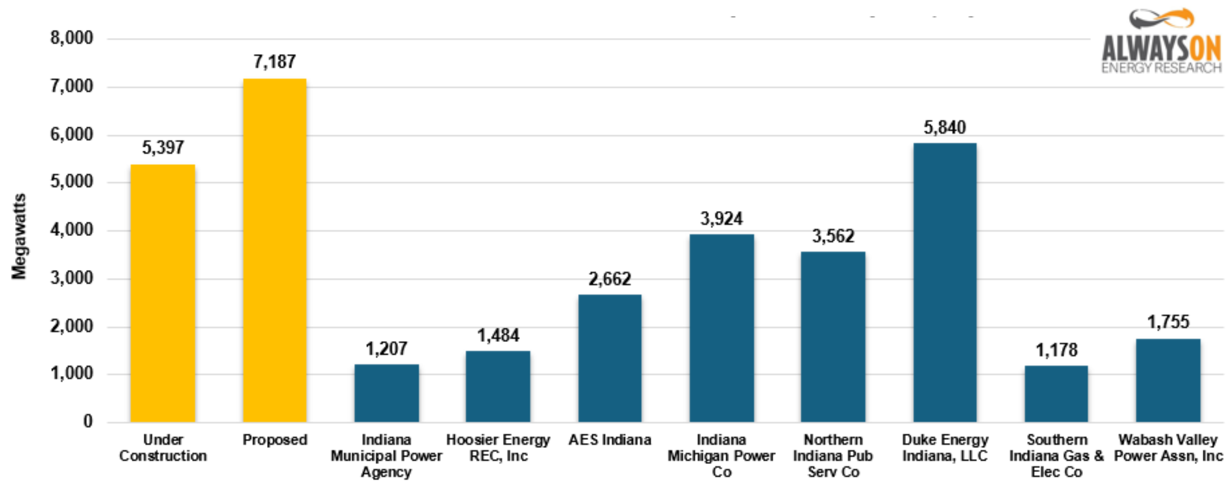
3 Enel, "MISO's 2025 Capacity Auction Results: Summer Prices Soar," May 14, 2025, https://www.enelnorthamerica.com/insights/blogs/miso-2025-capacity-auction-results?.

4 Ethan Howland, "PJM Capacity Prices Hit Record High As Grid Operator Falls Short of Reliability Target," Utility Dive, December 18, 2025, https://www.utilitydive.com/news/pjm-interconnection-capacity-auction-data-center/808264/.

5 Citizens Action Coalition, "Indiana Proposed Data Center Locations: 2025," Accessed January 20, 2026, https://perma.cc/8YU4-M4W4.

6 U.S. Energy Information Administration, "Operational Data 2024, EIA-861," Accessed January 20, 2026.

FIGURE 3: DATA CENTER DEMAND VS. PEAK SUMMER DEMAND BY INDIANA UTILITY COMPANY



Data Sources: U.S. Energy Information Administration, Citizens Action Coalition

Figure 3. There are currently 5,397 MW of data centers under construction in Indiana, which nearly equals Duke Energy's peak power demand, the state's largest utility.

If proposed data center projects come online, electricity demand will likely exceed Indiana's in-state power plant capacity, requiring investment in new resources to meet new power needs.

This analysis used the Levelized Cost of Energy (LCOE) metric to evaluate the lowest cost means of providing electricity to Indiana's existing households and businesses, and to determine how best to add the resources needed to meet the demand for data centers.

WHAT IS THE LEVELIZED COST OF ENERGY?

LCOE estimates are a common metric for comparing the costs of electricity from different generation resources. They are an estimate of the cost of generating electricity from various types of power plants, on a per-unit-of-electricity-generated basis, generally megawatt-hours (MWhs), over an assumed lifetime and quantity of electricity produced by the plant.

In other words, LCOE estimates are essentially like calculating the cost of your car on a per-mile-driven basis after accounting for expenses like initial capital investment, loan and insurance payments, fuel costs, and maintenance, divided by the number of miles driven in the car.

For power plants, these costs consist of capital costs (the cost of building the power plant), utility returns (the profits made by investor-owned utilities when they spend capital), fuel costs, fixed and variable operations and maintenance costs (employees, insurance, maintenance, etc.), and property taxes, divided by the total lifetime MWh generation of the resource (see Figure 4).

FIGURE 4: COSTS OF POWER PLANTS

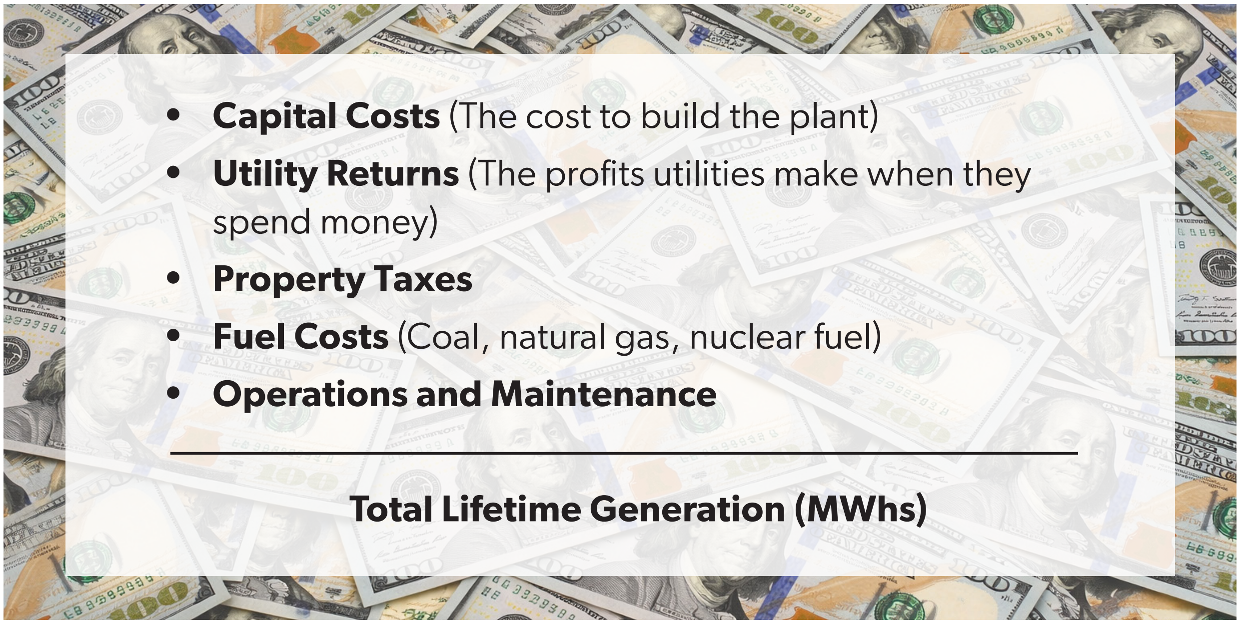


Figure 4. The LCOE is the total cost of generating electricity from a power plant, divided by the total generation of the plant over time.

RESULTS

AOER's cost modeling indicates the lowest-cost way to meet Indiana's electricity demand is to maintain the existing natural gas and coal resources on the grid while building new CC natural gas plants to meet rising demand (see Figure 5).[7]

Based on data from 2024, Indiana's existing hydroelectric facilities, CC natural gas, and coal facilities have lower levelized costs than most new forms of generation, generating electricity for $17.75 per MWh, $29.14 per MWh, and $55.22 per MWh, respectively.

These existing resources can generate lower-cost electricity than new plants because they are largely depreciated, meaning their upfront capital costs have been paid off. As a result, fuel costs constitute the largest cost for existing CC natural gas and coal facilities (see Figure 6).

For new resources, only new CC natural gas plants, which would produce power for $53.09 per MWh, are competitive with existing resources, with the LCOE of these plants slightly below the cost of existing coal plants.[8] New CT natural gas plants would cost $84.49 per MWh, and new nuclear plants would cost $122.18 per MWh (see Figure 7).

New plants are generally more expensive than existing ones because they are paying back the capital costs

7 See LCOE Assumptions in the Appendix.

8 Ibid.

FIGURE 5: LEVELIZED COST OF ENERGY FOR EXISTING AND NEW POWER PLANTS IN INDIANA

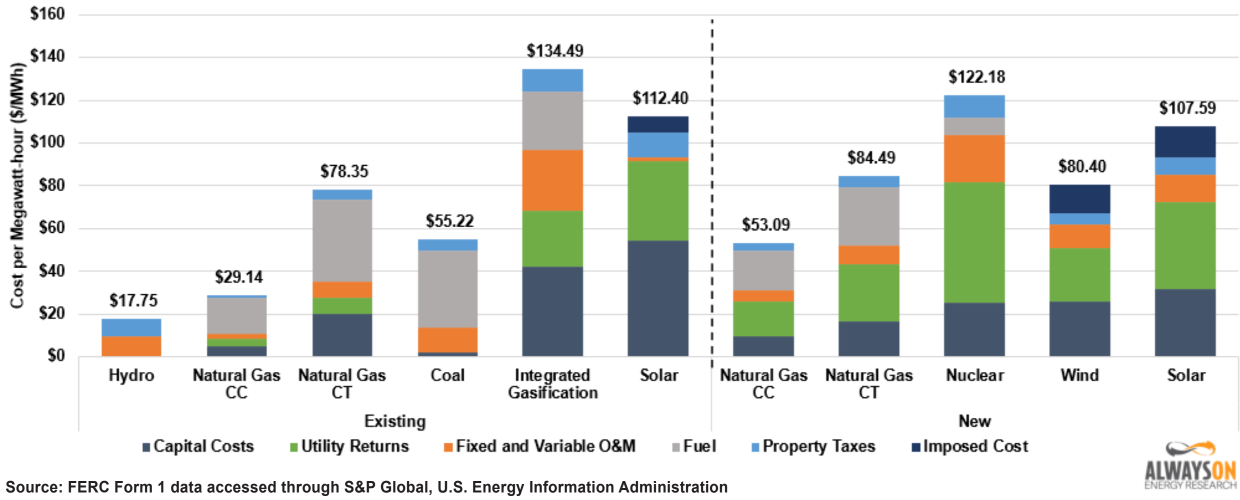


Figure 5. Utilizing existing Indiana CC natural gas and coal power plants is lower cost than building new ones, in most circumstances.

FIGURE 6: LEVELIZED COST OF ENERGY FOR EXISTING INDIANA POWER PLANTS

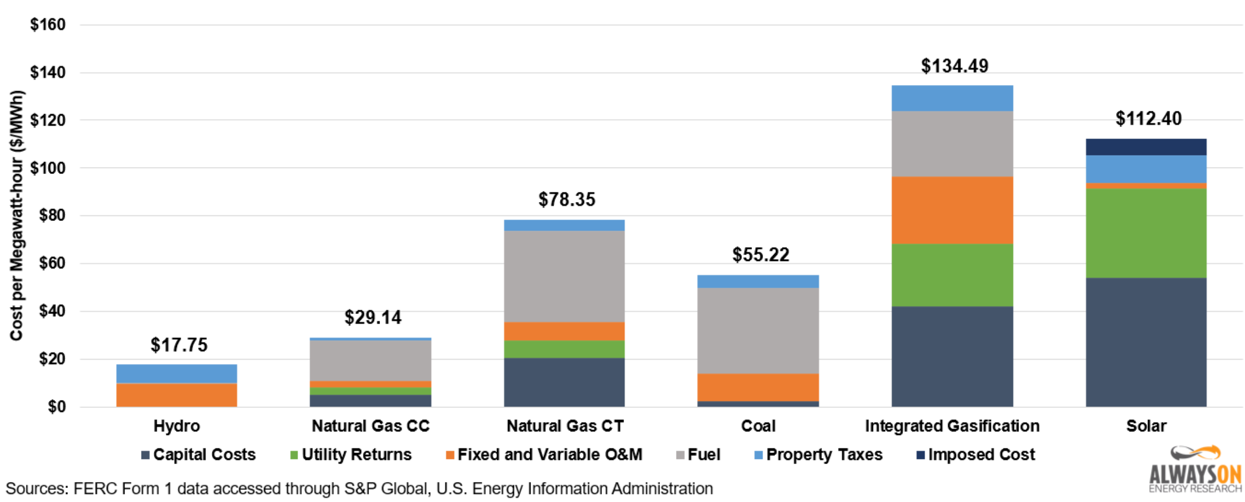


Figure 6. Existing hydro, CC natural gas, and coal have paid off nearly all their upfront capital costs, therefore reducing these costs, and utility profits.

FIGURE 7: LEVELIZED COST OF ENERGY FOR NEW INDIANA POWER PLANTS

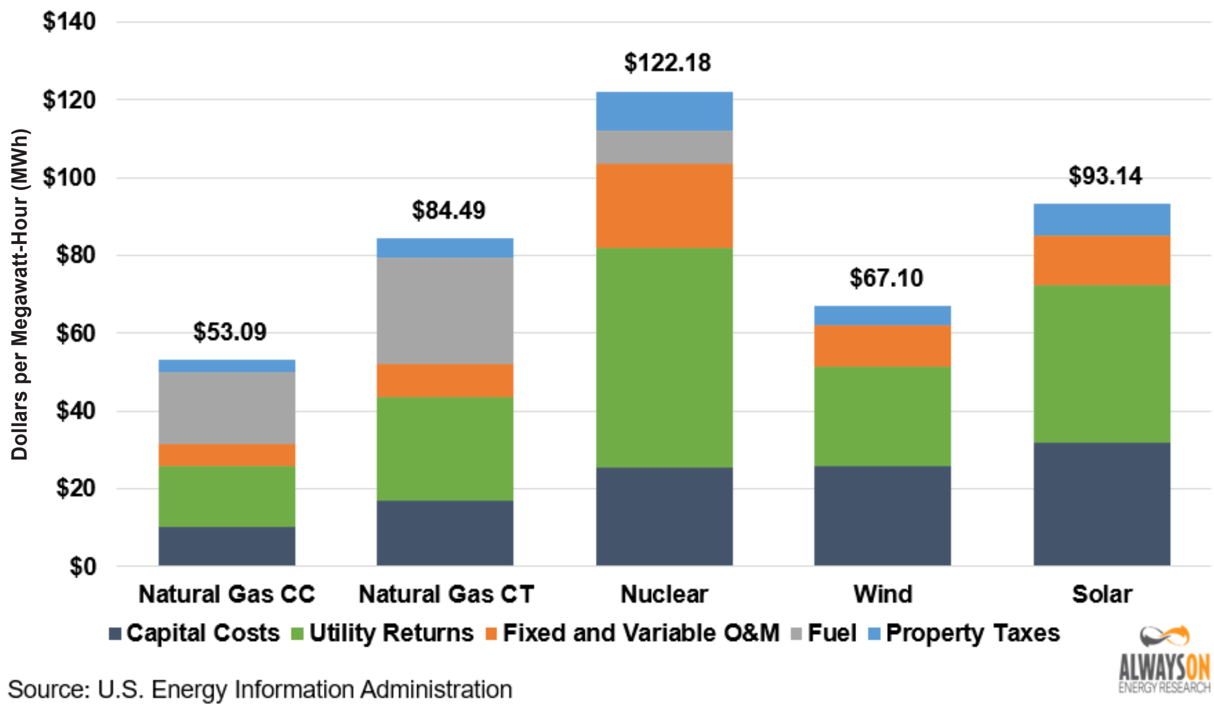


Figure 7. This graph shows that CC natural gas would be the lowest-cost new resource to add, while nuclear power would be the costliest option for new power generation.

to build the plant, like paying down the mortgage on a house, and they are paying for the utility profits, or rate-of-return, earned when a utility spends money on new infrastructure.

A BRIEF NOTE ON INDIANA MONOPOLY UTILITIES

Although investor-owned utilities in Indiana, like Duke, Northern Indiana Public Service Company (NIPSCO), Indiana Michigan Power, AES, and Vectren/CenterPoint, have shareholders, they are not truly private companies. They are government-approved, vertically-integrated monopoly utilities with the exclusive right to sell electricity in their service territory.

Because customers have no choice but to buy their power from the monopoly, it would be unfair to let the company charge whatever it wishes for electricity. As a result, electricity prices are generally set by government regulators using a mathematical formula called the Cost-of-Service formula.

In its most basic form, the formula states that utilities are allowed to charge enough for their electricity to cover the cost of providing the service to everyone in their service territory, *plus* a government-approved profit, often five to 10 percent, on their capital investments.

As long as the expenses are approved by the regulator in their state, utilities make a profit on every dollar they spend on new builds, such as wind turbines, solar panels, natural gas plants, or even renovating corporate offices. The more money utilities spend, the more money they make.

On the other side of this equation is depreciation. Every year, the company pays off a little bit more of the plant, and as a result, they no longer profit from this depreciated capital expense.

Once a power plant is paid off entirely, the utility no longer makes any profit from the facility. From the perspective of customers, fully depreciated power plants, like the coal plants shown in Figure 5, offer some of the lowest-cost sources of electricity on the grid. From the perspective of the utility, they're no longer a means for growing earnings.

As a result, utilities have a powerful financial incentive to work against the interests of their customers by retiring reliable, low-cost existing generators so they can spend as much money as possible building new infrastructure to put in their rate base, thus maximizing their government-approved profits.

Prior to the surge in electricity demand from data centers, this incentive structure led utilities to retire depreciated coal plants and replace them with new wind, solar, and natural gas facilities to maximize corporate profits. However, the sheer demand for these proposed data centers has led to intense debate about the costs associated with building the power generation facilities necessary to power these facilities.

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LIMITATIONS OF LCOE: EVALUATING THE SYSTEM COSTS OF INTERMITTENT RESOURCES

Traditional LCOE estimates were well-suited for comparing the costs of dispatchable resources, such as natural gas, coal, nuclear, and, to some degree, hydroelectric power, which can be turned on as needed to generate power.

However, LCOE is a less useful metric for assessing the true cost of non-dispatchable wind and solar resources to the grid because they do not provide the same reliability attributes as dispatchable plants. As a result, the LCOE estimates are not an apples-to-apples comparison of the cost of delivering similar *value* to the system.

This limitation of LCOE has resulted in wind and solar advocates misrepresenting Lazard or U.S. Energy Information Administration (EIA) LCOE estimates, suggesting that wind and solar are now lower cost than other energy sources without acknowledging this difference in system value.

For example, Lazard and EIA LCOE estimates only show the cost of operating a single wind or solar facility at its maximum reasonable output; they do not convey the cost of reliably operating an entire electricity system when the wind is not blowing or the sun is not shining.[9] Doing so increases the cost of running the entire electric grid through imposed costs, backup or firming costs, additional transmission requirements, and, in systems with a heavy reliance on wind and solar generators, overbuilding and curtailment costs.

AOER's Indiana LCOE analysis accounts for the imposed costs and firming costs and attributes them to the wind and solar generators that require them, thereby producing the apples-to-apples comparison needed to make the most informed decisions on behalf of Indiana families and businesses.

9 Lazard has begun to incorporate firming costs into its LCOE+ report; however, these are not prominently presented as a high-end cost of intermittent resources in their graphs.

FIGURE 8: LEVELIZED COST OF ENERGY FOR NEW INDIANA POWER PLANTS INCLUDING IMPOSED COSTS

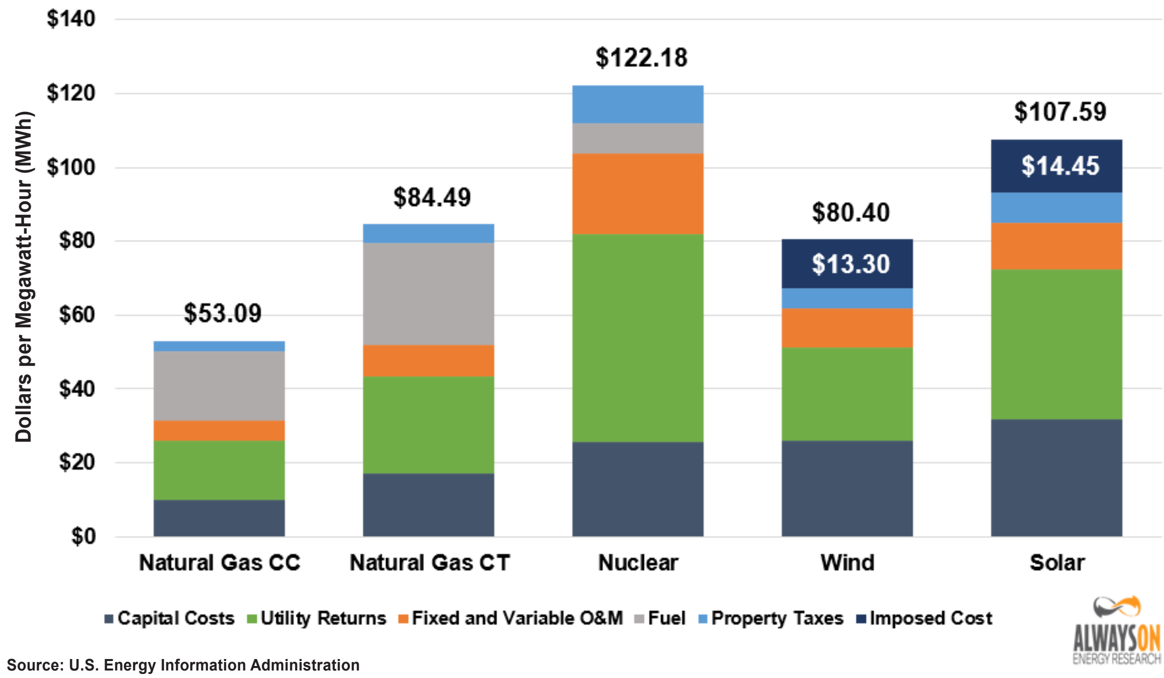

Figure 8. The imposed cost for wind facilities is $13.30 per MWh, and the imposed cost of solar is $14.45 per MWh.

Transmission costs are also increasing, as MISO has recently approved $22 billion in additional transmission spending to accommodate state policies mandating more wind and solar facilities.[10] Costs for transmission are not included in this analysis due to their site-specific nature, and overbuilding and curtailment costs are omitted because these are system-specific values based on the generating portfolio of individual utilities and states.

IMPOSED COSTS

For power plant economics, the facility's capacity factor, which is the percentage of electricity generated by a power plant compared to its theoretical output, is key. Producing more MWhs allows the facility to spread its fixed costs, such as upfront capital costs, utility returns, property taxes, staffing, and maintenance, over more "miles," effectively lowering the cost of generating electricity from the power plant.

Imposed costs are incurred when the construction of new wind or solar power-generating facilities causes new or existing dispatchable power plants to operate less frequently without being able to replace the reliable capacity that the existing facilities provide. Reducing the capacity factor of the existing plants increases their costs on a per MWh basis (see Figure 8).[11]

10 Ethan Howland, "Five Utility Commissions Ask FERC to Undo MISO's $22B Multi-Value Transmission Portfolio," Utility Dive, July 31, 2025, https://www.utilitydive.com/news/ferc-complaint-mvp-multi-value-project-transmission/756411/.

11 See Imposed Costs in the Appendix.

FIGURE 9: LEVELIZED COST OF ENERGY FOR EXISTING AND NEW POWER PLANTS IN INDIANA WITH FIRMING

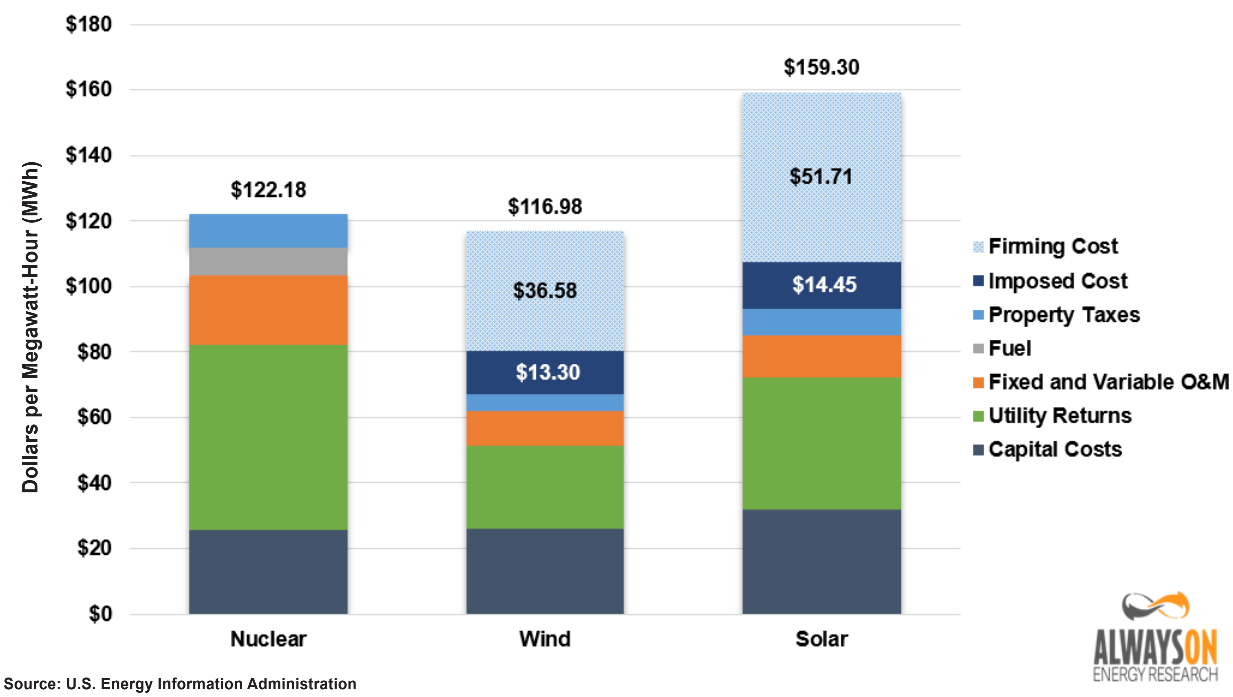

Figure 9. Once firming costs are accounted for, solar costs more than nuclear power, and wind is only slightly less than new nuclear.

FIRMING COSTS

Firming costs are incurred by the need to have backup facilities, whether natural gas or battery storage, to keep the lights on during periods of low or no wind or solar generation. Acknowledging the shortcomings of its previous LCOE calculations, Lazard has begun incorporating firming costs into its Levelized Cost of Energy+ report.

AOER used a modified version of the Lazard LCOE firming methodology to calculate Indiana-specific firming costs for new wind and solar resources based on local conditions. AOER found the levelized firming cost of new wind is $36.58 per MWh, and the levelized firming cost of solar is $51.71 per MWh, shown in Figure 9.[12]

Firming costs for solar are higher than wind because wind facilities are assumed to have a 36 percent capacity factor, whereas solar capacity factors are assumed to be 20 percent. As a result, the cost of backup generation is spread over more MWh of wind than of solar.

PRICE SENSITIVITY ANALYSIS

AOER's analysis found that existing coal and new CC natural gas are cost competitive. However, the current

12 The key differences between the methodology used by AOER and Lazard are discussed in the Appendix.

FIGURE 10: LEVELIZED COST OF EXISTING INDIANA COAL PLANTS AT VARIOUS CAPACITY FACTORS

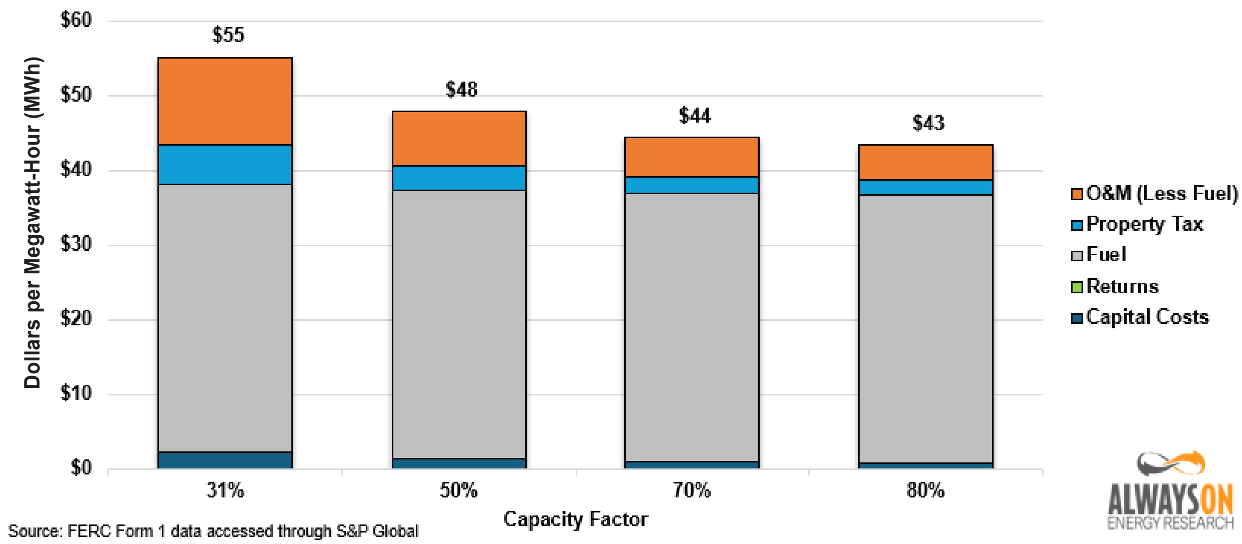

Figure 10. Higher capacity factors reduce the fixed costs of Indiana's existing coal plants on a per MWh basis, reducing the LCOE.

cost of the coal fleet is influenced by its relatively low-capacity factor of 31 percent. Increasing the fleet-wide capacity factor of Indiana's coal plants to 50 percent would reduce the LCOE by $7 per MWh, and increasing the capacity factor to 70 percent would reduce the LCOE by $9 per MWh, firmly below the cost of new CC natural gas plants (see Figure 10).

Figure 11 shows the price of electricity and capacity factors of the existing coal fleet for which Federal Energy Regulatory Commission (FERC) Form 1 data are available. The facilities with the lowest capacity factors generally have the highest costs per MWh, while plants operating at higher capacity factors produce power at lower cost.

Figure 12 shows how increasing the capacity factors of these plants could decrease their LCOEs, with the low-end costs reflecting 80 percent capacity factors, the high-end costs reflecting a 20 percent capacity factor, and the red dots showing the price at 2024 capacity factors. Plants like Michigan City, Petersburg, and R.M. Schahfer could substantially reduce their total levelized costs by increasing electricity production.

AOER also conducted capacity-factor sensitivity analyses for the other resources evaluated in this report to show the costs per MWh under a range of utilization assumptions. These capacity factor sensitivities are explained in greater detail in the Appendix.[13]

The results below indicate that existing resources are consistently lower cost than new resources, and that wind and solar, with imposed and firming costs included, are more than twice as expensive as existing coal facilities, even though they were operating at only

13 See Capacity Factor Sensitivities in the Appendix.

FIGURE 11: EXISTING COAL PLANT COSTS AT 2024 CAPACITY FACTORS

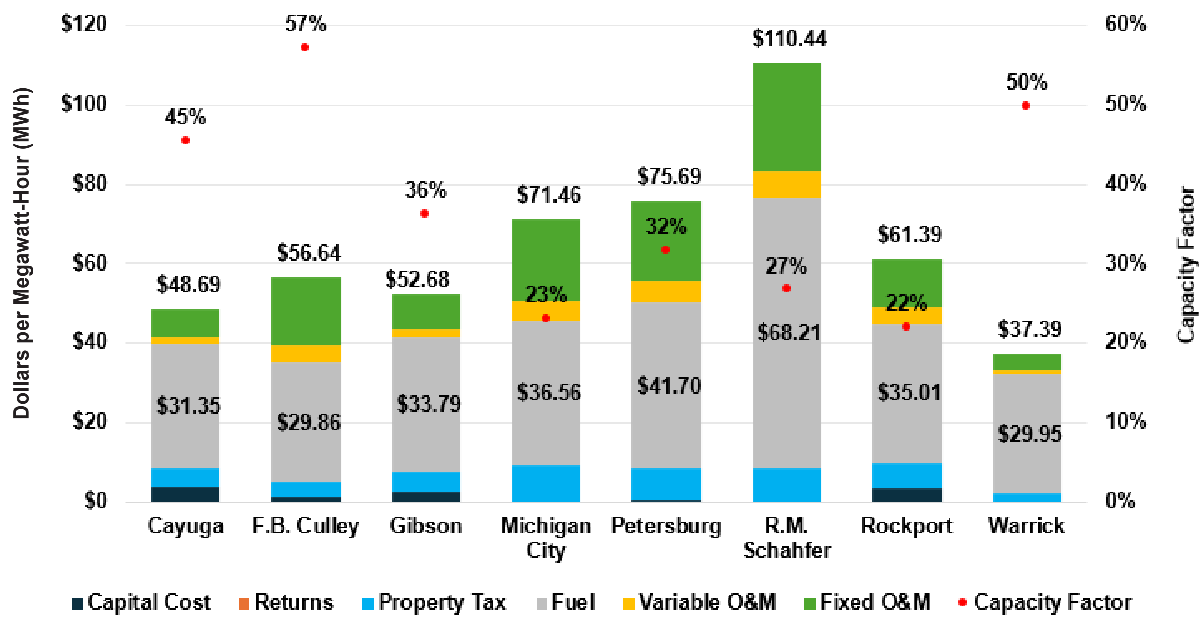

Figure 11. Coal plants with higher capacity factors tend to have lower LCOEs because they can spread their fixed costs over more MWhs.

FIGURE 12: RANGE OF LCOES FOR EXISTING INDIANA COAL PLANTS, 80 TO 20 PERCENT CAPACITY FACTOR

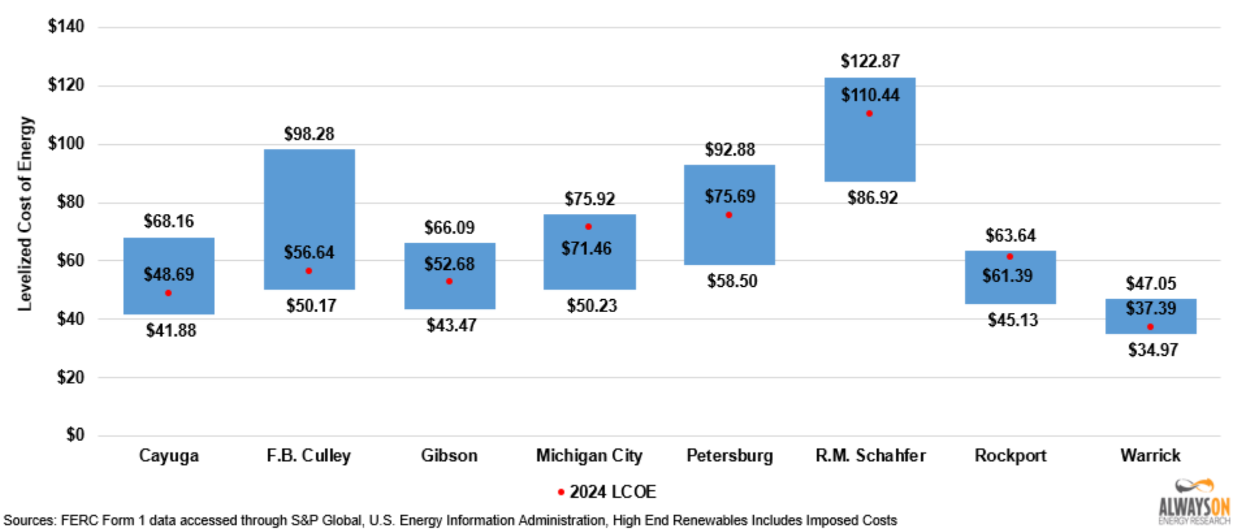

Figure 12. The low-end costs assume 80 percent capacity factors, while the high-end costs assume a 20 percent capacity factor.

FIGURE 13: THE LEVELIZED COST OF INDIANA ENERGY RESOURCES

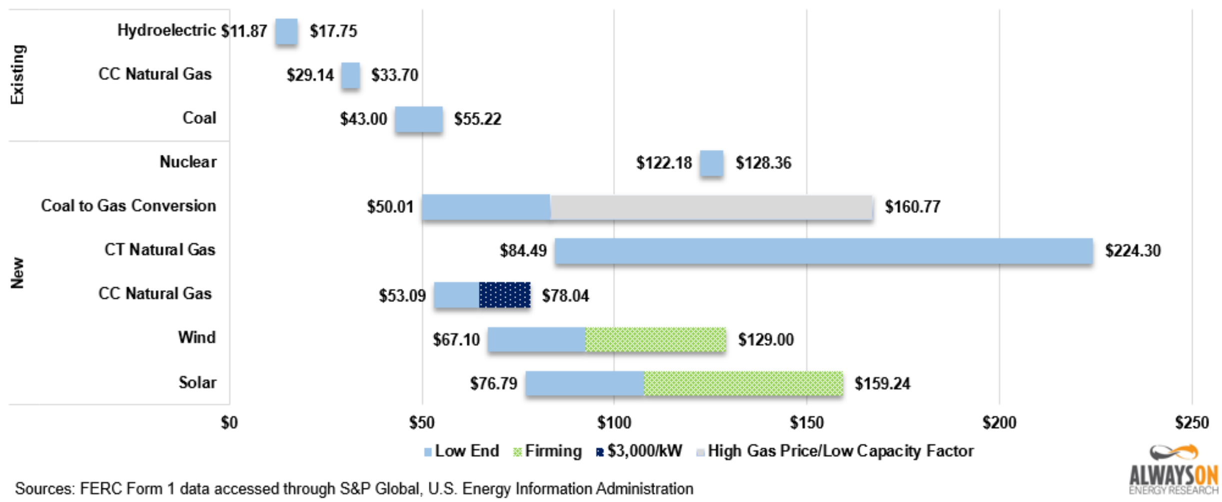

Figure 13. Existing resources are lower cost than new resources when realistic capacity factor variations are evaluated.

31 percent capacity factors (see Figure 13).

Figure 13 also shows a high-end range for CC natural gas plants that assumes higher capital costs than our base analysis. This sensitivity evaluates the cost of CC natural gas if the capital cost is $3,000 per kilowatt (kW) of installed capacity, rather than the $2,200 used in the base case, to examine the impact of higher capital costs on plant economics.

This higher capital cost would increase the high-end cost of CC natural gas by $13 per MWh, from $65.04 per MWh to $78.04 per MWh.

Lastly, the chart shows the range of cost estimates for wind and solar resources, attributing the imposed and firming costs to the high-cost scenario, but these additional costs are not attributed to wind and solar in the low-cost scenario. When imposed and firming costs are properly accounted for, new CC natural gas is the most affordable option for new power generation in Indiana.

CONCLUSION

This LCOE analysis demonstrates that 75 percent of Indiana's existing coal facilities can generate electricity at a lower cost than new CC natural gas plants, the most affordable new resource available, especially if these plants can increase their utilization rates.

Indiana's expected increase in data center demand would be well-suited to increasing the capacity factors of these coal plants, as they can provide baseload power around the clock. It is also important to note that the fleet-wide capacity factor of Indiana's CC natural gas plants was 83 percent in 2024, meaning there is little room for these facilities to increase generation and provide incremental energy to data centers or other customers.

In the end, if keeping rates as low as possible, boosting regional reliability, and enabling the fast interconnection of data centers to the grid are top priorities among Indiana policymakers, it is difficult to beat the value proposition of maintaining the existing coal fleet.

APPENDIX

Assumptions for Existing Resources

Capital Costs: Federal Energy Regulatory Commission (FERC) Form 1 data were obtained through S&P Global Capital IQ.

Remaining capital costs are estimated using initial capital costs, plant in-service dates, and estimated remaining book life.

Utility Returns: Returns are estimated as a debt/equity split of 48:52 with a five percent return on debt and 10 percent return on equity based on the estimated remaining book life of assets.

Fixed and Variable O&M: Obtained from S&P Global Capital IQ.

Property Taxes: Calculated at one percent of the total capital cost of power facilities based on data provided by 2024 FERC Form 1 filings.

Fuel Costs: Based on data provided by 2024 FERC Form 1 filings in Indiana.

Heat Rates: Obtained from S&P Global Capital IQ.

Capacity Factors: S&P Global Capital IQ capacity factor data for 2024 were used for existing resources. EIA annual capacity factor data for 2024 were used for new CC natural gas plants.

Hydroelectric: High-cost scenario, 41.1 percent; low-cost scenario, 60 percent.

CC natural gas: High-cost scenario, 83 percent.

CT Natural Gas: 18 percent per EIA data.

Coal: 31 percent per S&P Global.

New Resources

Capital Costs: All capital cost assumptions, except CC natural gas, use overnight capital costs from Region 4 of the EIA Annual Energy Outlook (AEO) 2025 Electricity Market Module (EMM). CC natural gas plants are assumed to cost $2,200 per kW based on recent market trends. A high capital cost scenario of $3,000 per kW was run to show potential costs if current trends in the natural gas turbine market persist.

Utility Returns: Returns are estimated as a debt/equity split of 48:52 with a five percent return on debt and 10 percent return on equity.

Property Taxes: Calculated at one percent of total capital cost of power facilities based on assumptions from the EIA AEO 2025.

Fixed and Variable Operations and Maintenance: EIA AEO 2025 EMM assumptions for all new technologies.

Fuel Costs: Natural gas is assumed to cost $3 per million British Thermal Units (MMBtu). Nuclear is $0.80 per MMBtu.

Heat Rate: EIA AEO 2025 EMM assumptions for all technologies.

Useful Plant Life Assumptions

- Wind: 20 years based on National Renewable Energy Laboratory estimates.
- Solar: 25 years based on common industry warranties.
- CC Natural Gas: 30-year financial life based on EIA.
- CT Natural Gas: 30-year financial life.
- Nuclear: 40-year financial life based on initial operating license.

Capacity Factors

- Wind: High-End Cost 30 percent based on statewide performance in 2024. Low-End Cost: 36 percent based on the best-performing assets from Lawrence Berkeley Labs data.
- Solar: High-End Cost 20 percent based on the most recent EIA data. Low-End Cost: 25 percent.
- Natural Gas CC: High-End Cost 60 percent, representative of use in other parts of the country. Low-End Cost: 83 percent based on the utilization rates of existing CC natural gas facilities from the most recent EIA data.
- Natural Gas CT: High-End Cost five percent based on generally observed capacity factors for these resources. Low-End Cost: 18 percent based on the utilization rates of existing CT natural gas facilities from 2024 EIA data.
- Nuclear: High-End Cost 90 percent. Low-End Cost: 95 percent based on commonly observed plant performance in other regions.

Capacity Factor Sensitivities

A range of capacity factor assumptions was used in Figure 13. These assumptions for the low- and high-cost scenarios can be seen in Table 1.

Capacity Factor Sensitivities			
	Resource	Low Cost	High Cost
New	Solar	25%	20%
	Wind	36%	30%
	CT Natural Gas	18%	5%
	CC Natural Gas	83%	60%
	Nuclear	95%	90%
Existing	Coal	80%	31%
	CC Natural Gas	80%	31%
	Hydroelectric	60%	41%

Table 1. The low-cost scenarios have higher capacity factors, and the high-cost scenarios have lower capacity factors.

Imposed Costs

The imposed cost of wind and solar is derived from the need to cover the fixed costs of coal over fewer Megawatt-hours (MWhs) of coal generation. The difference is then applied to the LCOE of wind and solar.

The fixed cost of existing coal is $13.97/MWh at capacity factors of 31.3 percent based on FERC Form 1 data. This equates to $15.08 at 29 percent capacity factors that would exist on the 1,000 MW system if coal served it alone.

New Wind Example:

The average load for the system is 415.5 MW.

Wind supplies 10 percent of this load and would require 115 MW of capacity based on capacity factors of 36 percent, which contributes 14 MW of firm capacity based on 11.8 percent capacity values.

Coal supplies the remaining need for firm capacity of 1,136 MW, which results in 1,416 MW of total capacity based on 1,416 MW of total capacity.

Adding wind reduces coal capacity factors to 26 percent, resulting in fixed costs of $16.56. The difference in fixed cost is $1.48.

Applying this to new wind generation, the cost is multiplied by nine (because wind generation is 1/9th of coal generation), resulting in a total cost of $13.30/MWh.

Levelized Firming Costs

- For this analysis, AOER used a modified version of Lazard's levelized cost of firming methodology.
- Key differences stem from our use of the Cost of New Entry (CONE) in MISO, not the Net Cone, and our use of MISO's pending Direct Loss of Load (DLOL) capacity accreditation rather than Effective Load Carrying Capability (ELCC) as the basis of its firming cost.
- The firm capacity value of a new resource is calculated as Nameplate Capacity × DLOL %, where: (1) Nameplate Capacity of a resource refers to its maximum potential energy output, and (2) DLOL measures the performance of a resource at times of greatest "capacity need" for the system in 2030.
- Over time, increased renewable penetration or changes in demand patterns can shift the timing of the capacity need, greatly reducing the DLOL accreditation awarded to intermittent resources.
- The remaining non-firm capacity (Nameplate Capacity × (1 – (DLOL %))) is "firmed" at the CONE, a $130.7/kW year figure that is intended to reflect capital and operating costs for a new, firm resource (e.g., gas peaker, or battery storage).
- CONE is assessed and published by grid operators for each regional market.
- The Levelized Firming Cost is defined as the additional capacity payment, priced at CONE, required to bring the DLOL of the combined system (intermittent and firming resource) to 100%.

- The LCOE plus Levelized Firming Cost varies between ISOs, due to:
    - (1) the standalone LCOE in the region based on the regional capacity factors for wind or solar;
    - (2) the DLOL value of the standalone renewable resource; and
    - (3) the region's CONE.

Nameplate Capacity (kW) × (1 – DLOL (%)) × CONE ($/kW-month) × 12 Months Nameplate Capacity (MW) × Regional Capacity Factor (%) × 8,760 Hours = Levelized Firming Cost ($/MWh)

LCOE Assumptions for New Resources		Capacity	Capital Cost	Capital Recovery Factor	Fixed O&M Cost	Capacity Factor	Fuel Cost	Heat Rate	Variable O&M Cost	Debt Ratio	Equity Ratio	Interest (i)	Years (n)
		MW	($/kW)	%	($/kW-yr)	%	($/MMBtu)	(Btu/kWh)	($/MWh)	%	%	%	n
Solar	Low	1,000	$1,412	9.05%	$22.91	25.00%	$0.00	0	$0.00	48%	52%	8%	25
	Medium	1,000	$1,412	9.05%	$22.91	20.20%	$0.00	0	$0.00	48%	52%	8%	25
	High	1,000	$1,412	9.05%	$22.91	20.20%	$0.00	0	$0.00	48%	52%	8%	25
Wind	Low	1,000	$1,636	9.88%	$33.55	36.00%	$0.00	0	$0.00	48%	52%	8%	20
	Medium	1,000	$1,636	9.88%	$33.55	30.00%	$0.00	0	$0.00	48%	52%	8%	20
	High	1,000	$1,636	9.88%	$33.55	30.00%	$0.00	0	$0.00	48%	52%	8%	20
Natural Gas Combined Cycle	Low	1,000	$2,200	8.55%	$15.75	83.10%	$3.00	6,226	$3.39	48%	52%	8%	30
	Medium	1,000	$2,200	8.55%	$15.75	60.00%	$3.00	6,226	$3.39	48%	52%	8%	30
	High	1,000	$3,000	8.55%	$15.75	60.00%	$3.00	6,226	$3.39	48%	52%	8%	30
Natural Gas Combustion Turbine	Low	1,000	$812	8.55%	$6.97	18.20%	$3.00	9,142	$4.05	48%	52%	8%	30
	Medium												
	High	1,000	$812	8.55%	$6.97	5.00%	$3.00	9,142	$4.05	48%	52%	8%	30
Nuclear	Low	1,000	$8,500	8.03%	$158.61	95.00%	$0.80	10,452	$2.54	48%	52%	8%	40
	Medium												
	High	1,000	$8,500	8.03%	$158.61	90.00%	$0.80	10,452	$2.54	48%	52%	8%	40

LCOE Cost Breakdown for New Resources		Capital Costs	Utility Returns	Fixed and Variable O&M	Fuel	Property Taxes	Imposed Costs	Firming Costs	Total
Solar	Low	$25.79	$32.56	$10.46	$0.00	$7.98			$76.79
	Medium	$31.92	$40.30	$12.95	$0.00	$7.98	$14.45		$107.59
	High	$31.92	$40.30	$12.95	$0.00	$7.98	$14.45	$51.65	$159.24
Wind	Low	$25.94	$25.34	$10.64	$0.00	$5.19			$67.10
	Medium	$31.13	$30.40	$12.77	$0.00	$5.19	$13.30		$92.78
	High	$31.13	$30.40	$12.77	$0.00	$5.19	$13.30	$36.58	$129.36
Natural Gas Combined Cycle	Low	$10.07	$15.76	$5.55	$18.68	$3.02			$53.09
	Medium	$13.95	$21.83	$6.39	$18.68	$4.18			$65.03
	High	$19.03	$29.77	$6.39	$18.68	$4.18			$78.04
Natural Gas Combustion Turbine	Low	$16.98	$26.57	$8.42	$27.43	$5.09			$84.49
	Medium								$0.00
	High	$61.80	$96.71	$19.96	$27.43	$18.54			$224.43
Nuclear	Low	$25.53	$56.47	$21.60	$8.36	$10.21			$122.17
	Medium								$0.00
	High	$26.95	$59.61	$22.66	$8.36	$10.78			$128.36

LCOE Cost Breakdown for Existing Resources	Capacity	Capacity Factor	Fixed O&M	Fuel Cost	Heat Rate	Variable O&M	Debt Ratio	Equity Ratio	Interest	Total LCOE
	MW	%	($/MWh)	($/MWh)	(Btu/kWh)	($/MWh)	%	%	%	($/MWh)
Solar	85	20%	$1.62	$0.00	0	$0.40	48%	52%	7.6%	$105.15
Natural Gas Combined Cycle	1,546	83%	$2.39	$17.15	7,265	$0.60	48%	52%	7.6%	$29.14
Natural Gas Combustion Turbine	3,202	10%	$7.72	$38.28	13,217	$1.93	48%	52%	7.6%	$78.35
Natural Gas Steam	663	56%	$6.73	$30.82	11,968	$1.94	48%	52%	7.6%	$41.27
Coal	10,922	31%	$11.62	$35.83	11,430	$3.07	48%	52%	7.6%	$55.22
Hydro	105	40%	$9.91	$0.15	0	$2.12	48%	52%	7.6%	$17.75