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REREGULATING NUCLEAR GENERATION IN OHIO:

Why Reviving Ratepayer Risk Is the Wrong Strategy To Enable New Nuclear Power

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REREGULATING NUCLEAR GENERATION IN OHIO:

Why Reviving Ratepayer Risk Is the Wrong Strategy To Enable New Nuclear Power



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The findings, conclusions, and recommendations expressed are those of the authors. They do not represent the views of Cleveland State University or of the Northeast Ohio Public Energy Council.



EXECUTIVE SUMMARY

Nuclear power generation is enjoying newfound bipartisan support in many parts of the United States. Until the last few years, its principal support among policy makers has been due to nuclear power's ability to produce dispatchable, emissions-free electricity – increasingly important as the climate change crisis has arrived. In recent years, however, additional new interest has been created in nuclear energy by surging demand for more generation, principally from data centers, together with advances in nuclear power generation that promise to constrain costs.

Now policy makers are considering how best to enable nuclear power development in Ohio. Some members of the Ohio General Assembly have called for reregulating electricity generation, in part, by allowing distribution utilities in Ohio to build, own and operate new nuclear power plants. Their argument is that new nuclear generation will not likely be built in Ohio without socializing the risk of cost overruns among the ratepayers. That may be true, but there are less risky ways to encourage the development of nuclear power in Ohio. JobsOhio, for instance, has established funding for a "nuclear power center of excellence" in Ohio which targets the development of manufacturing and engineering for nuclear energy in Ohio.

Ohio deregulated its electricity generation industry in 2001 directly in response to the "rate shocks" of the 1980s caused by nuclear power cost overruns and delays. States that had invested heavily in nuclear power were experiencing a rapid rise in the cost of electricity that destabilized their economies. Ohio was one of those states – it had three different nuclear energy plants that experienced massive cost overruns, one of which was ultimately abandoned before completion as uneconomical. High electricity costs contributed to the loss of industry in Ohio, and a sense that Ohio had become a "rustbelt" economy. By the mid 1980s, the industrial cost of electricity was as high as $0.15/kWh ($2026), about 50% higher than it is today under Ohio's restructured electricity markets. Residential rates were at an astounding $0.25/kWh.

COST OVERRUNS FOR OHIO NUCLEAR POWER PLANTS, $2026

Project	Projected Cost	Final Cost	Cost Overrun
Davis-Besse No. 1	$557 million	$2.7 billion	4.8x
Zimmer Power Station	$2.2 billion	$5.4 billion (abandoned)	2.5x
Perry Nuclear Plant	$5.3 billion	$16.9 billion	3.2x

Year	Total
2011-2018	$21,278
2019	$2,725
2020	$2,612
2021	$2,714
2022	$2,734
2023	$2,702
2024 (est.)	$2,749
Total	$37,513

TOTAL SAVINGS DUE TO DEREGULATED ELECTRICITY GENERATION MARKETS IN OHIO 2011 - 2024
(millions of dollars)

Amounts are in 2023 dollars.

Meanwhile, the successful deregulation of the natural gas industry in the 1980s led the U.S. to develop wholesale electricity generation markets and to open access to interstate transmission lines. Between 2001-2011, Ohio transitioned to deregulated markets and began to attract competitive retail electric supply companies. As a result of this competition, Ohio ratepayers saved an estimated $37 billion between 2011-2024 – averaging nearly $3 billion per year. By customer class, annual savings have averaged $54,840 for industrial, $1,492 for commercial and $261 for residential users. Today, around 75-80% of users in Ohio elect to shop for their generation.

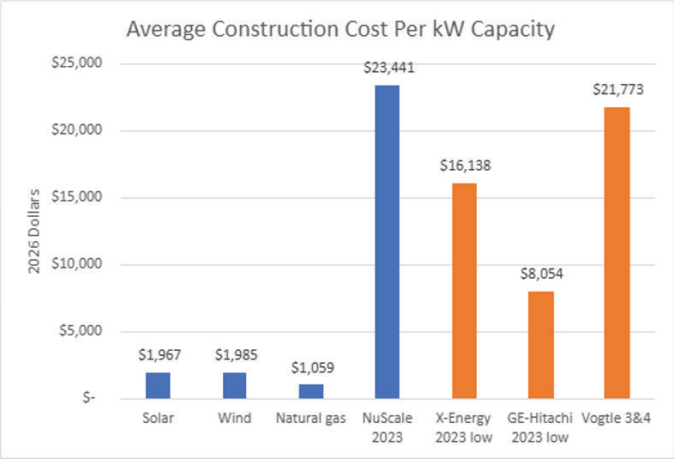
Reregulating nuclear power would reintroduce the same dynamics that plagued the industry from its inception in the 1960s: traditional utility regulation rewards investment into capital-intensive projects by ensuring the investors a high rate of return with little risk. And nuclear power plants are famously capital-intensive. Reregulating nuclear generation will likely yield the same result as before: undisciplined investment decisions by utilities, leading them to overbuild generation and to underestimate time and costs.

It is unsurprising that utilities would like the ratepayers to subsidize nuclear power. **Construction costs for nuclear power plants are five times higher than for wind, solar or natural gas generation plants.** Even without cost overruns, the levelized cost of new nuclear power is around $88-119/MWh. Wind and solar range from $25-58/MWh. According to the Energy Information Agency, natural gas generation with carbon capture and sequestration will be around $58/MWh by 2031 – before any new nuclear plants will be in operation.

What's more, it is unclear whether utilities can constrain the cost overruns that have made nuclear power so risky to build. Idaho National Labs, the nation's leading nuclear energy lab, found that U.S. nuclear plant cost overruns have averaged 286% since the accident at Three-Mile Island in 1979. A recent study from Boston University which looked at international generation costs over 50 plus years found that while most new generation suffers from cost overruns, nuclear power continues to be the worst offender, with an average of 102% compared to an average overall of 40%.

Another reason that utilities give for why nuclear power should be reregulated is the anticipated rapid growth in demand for Ohio in the coming decade. This new demand is being driven in principal part by the ongoing deployment of new data centers. The concern policy makers have stems in part from Ohio's energy-intensive economy – Ohio ranks 7th in population, but 4th in energy consumption. Ohio's economy could be at risk if there is a shortage of local generation, or if climate change forces utilities to account for carbon emissions.

AVERAGE CONSTRUCTION COST FOR DIFFERENT GENERATION SOURCE ($2026)



Source: EIA for wind, solar and natural gas construction costs, and IEEFA for nuclear construction costs. Orange shows projected costs and blue shows actual costs.

The U.S. Energy Information Agency shares this concern. It projects that the U.S. will need another 600 terawatt-hours per year of generation by 2036. Ohio's 3.9% of this new load would require that Ohio build or purchase 23.4 TWhs per year. Nuclear energy might be a good candidate to supply this power, were it not for the 7-10 years it takes to build the plants. AEP Ohio has projected that most of the data center demand will arise before 2030.

Further, it appears that PJM has ample new generation on the way to meet this new demand. PJM reports that 811 new projects, with 220 GW of capacity, have applied to connect to the regional grid, 53 GW ready to be built. In January 2026, PJM reported it has 10 GW in signed interconnect agreements for Ohio. Berkeley Labs found 16.8 GW of new generation interconnection requests for Ohio in June 2026. If we conservatively assume a 20% capacity production vector for this power (e.g. 100% of the capacity is solar), this capacity already in the queue for Ohio alone would meet between 75-125% of Ohio's projected 2036 load. In short, it is unclear how much new generation will be required beyond that already planned.

This is not to say Ohio should not invest in nuclear power for the long term. Ohio has long been a leader in power system design and manufacturing and is positioned to be a leader in the nuclear industry supply chain. Investment now in nuclear power would position Ohio to respond to the predicament the nation may well face in 30 years as natural gas supplies dwindle, climate change worsens and the grid is saturated with intermittent renewable power.

But policy makers should carefully consider reregulation as a strategy for enabling nuclear generation in Ohio. Nuclear power is expensive, and cost overruns are likely to continue. Putting the costs into the rate base would drive up electricity costs. This would encourage large end users to leave the grid, leaving the remaining captured ratepayers to pick up a larger share of the higher costs.

Further, subsidized generation would chill participation by commercial retail electricity service providers in Ohio's energy markets, driving up prices. There are better ways to support the nuclear power industry in Ohio without undermining the competitive energy retail markets that have saved ratepayers $37 billion since 2011. JobsOhio's investment into nuclear energy manufacturing and supply chain development, for instance, does not put retail markets at risk.

Ohio has been down this path before. Vertically integrated regulation led to cost overruns that culminated in $0.25/kWh electricity rates in Ohio in the 1980s. Rather than repeat this mistake, Ohio should find ways to encourage the adoption of an advanced nuclear industry in the state without putting ratepayers at risk. Ohio can continue to encourage new nuclear energy through manufacturing and supply chain support. It can also welcome independent power producers to build nuclear power plants that compete with other generation – as it already does now.

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1 INTRODUCTION

1.1 Background

This study from Cleveland State University's (CSU) Energy Policy Center (the Study Team) has been undertaken in response to questions about the possible effects on ratepayers of enabling Ohio's Electric Distribution Utilities (EDUs) to own nuclear electricity generation. Under proposed new legislation[1] being contemplated by members of Ohio's General Assembly, Ohio's EDUs could build, own and operate nuclear power generation – and pass the costs of this on to Ohio ratepayers through their electric distribution rates. The statute comes at a time when Columbus, Ohio-based American Electric Power Company is exploring strategies to deploy small modular nuclear projects in Ohio, Indiana and Virginia – all targets for data center development.[2]

Nuclear power generation is enjoying newfound bipartisan support in many parts of the United States. Until the last few years, the principal support among policy makers has been due to nuclear power's ability to produce reliable emissions-free electricity[3] – increasingly important as climate change has arrived. In recent times, however, additional new interest has been created in nuclear energy by surging demand for more generation to support data centers and to address energy security concerns. New renewable power from solar and wind, it has been argued, will be insufficient to respond to this growing demand.[4] Accordingly, the argument goes, we need to build more nuclear power.

Notwithstanding these apparent advantages, two major criticisms have been leveled against nuclear power that have yet to be fully answered by advocates. First, nuclear power requires a long lead time before realizing commercial generation output – typically around 7-10 years.[5] And second, since its inception in the 1960s, the industry has been plagued by massive cost overruns. Without subsidies from ratepayers that protect utilities from suffering the consequences of cost overruns, it is unclear if or when new nuclear plants will

[1] Ohio House Bill 862 was proposed in May 2026 by Reps Adam Mathews and Bob Peterson. As of June 2026, it was still in House Committee for review. See: *https://www.legislature.ohio.gov/legislation/136/HB862*

[2] E. Howland, "AEP, other Ohio utilities could own nuclear power plants under state bill," Utility Dive, May 2026, *https://www.utilitydive.com/news/aep-ohio-nuclear-power-smr-bill-oma/820841/*

[3] Arguably, nuclear power is also cheap to operate – after the construction costs have been paid for. But due to the massive subsidies nuclear power has received and continues to receive, it is not easy to determine the true cost of nuclear power. These subsidies include, among other things, the U.S. Price-Anderson Act, which limits the liability utilities have to the public for catastrophic events such as a core melt down. *https://www.congress.gov/crs-product/IF10821*. How do we estimate the cost of the state ensuring a risk so massive that no insurance company would insure it?

[4] See, e.g. "Ashley Finan and Amy Roma on Speed, Safety, and Reforming Nuclear Energy," Columbia Energy Exchange, June 2, 2026, found at *https://podcasts.apple.com/us/podcast/ashley-finan-and-amy-roma-on-speed-safety-and/id1081481629?i=1000770822253*

[5] Some nuclear energy advocates recognize that plants cannot be brought online in time to support all the anticipated new AI data centers. They propose a natural gas turbine bridge strategy which will support the data centers until the nuclear construction can be completed. Id.



be built in Ohio. As Ohio Representative Adam Mathews, sponsor of a recent bill that would allow nuclear plants into the rate base, put it: "Every single nuclear power plant built in the United States has been vertically integrated [i.e. put into the rate base] in some way." [6] Or, as set forth recently in a study by the Institute for Energy Economics and Financial Analysis, nuclear power is still "too slow, too expensive and too risky" to compete today with renewables or natural gas generation.[7] Accordingly, nuclear power may require ratepayer subsidies to succeed in Ohio.

The Study Team does not herein seek to address the social value of nuclear power. That value is controversial and difficult to ascertain, in part because energy policy in the United States is generally set by advocacy among vested interests, rather than by balancing environmental, economic, health and national security interests. Should society seek to fairly account for externalities, such as the cost of climate change, policy makers may well conclude that society should more robustly subsidize nuclear power and other clean electricity generation.[8]

Instead, this Study examines the potential risks to Ohio's ratepayers should they be asked to bear the cost of new nuclear power generation, in whole or in part. This Study examines this risk in light of the industry's historical and continuing cost overruns, especially when less risky alternative strategies to address the same externalities may be available.

1.2 History of Nuclear Power in Ohio

Ohio, like much of America, enjoyed 25 years of post World War II (WW II) energy abundance and economic growth. During this era, the U.S. benefited from near complete energy self-sufficiency, relying principally on coal and fuel oil to make electricity. Until the 1970s, natural gas had been largely a by-product of oil production, and much of it was flared as waste.[9] Demand for electricity increased steadily, and as it did, utilities constructed new plants, with the costs of the plants and the grid passed through to ratepayers. Throughout the 1960s, inflation-adjusted costs of electricity continued to fall with the realization of economies of scale, especially through the adoption of ever-larger generation plants.[10]

[6] A. Staver, "Could Ohio repeat the mistakes behind its largest public corruption scandal?", May 17, 2026, Cleveland.com, *https://www.cleveland.com/news/2026/05/could-ohio-repeat-the-mistakes-behind-its-largest-public-corruption-scandal.html*

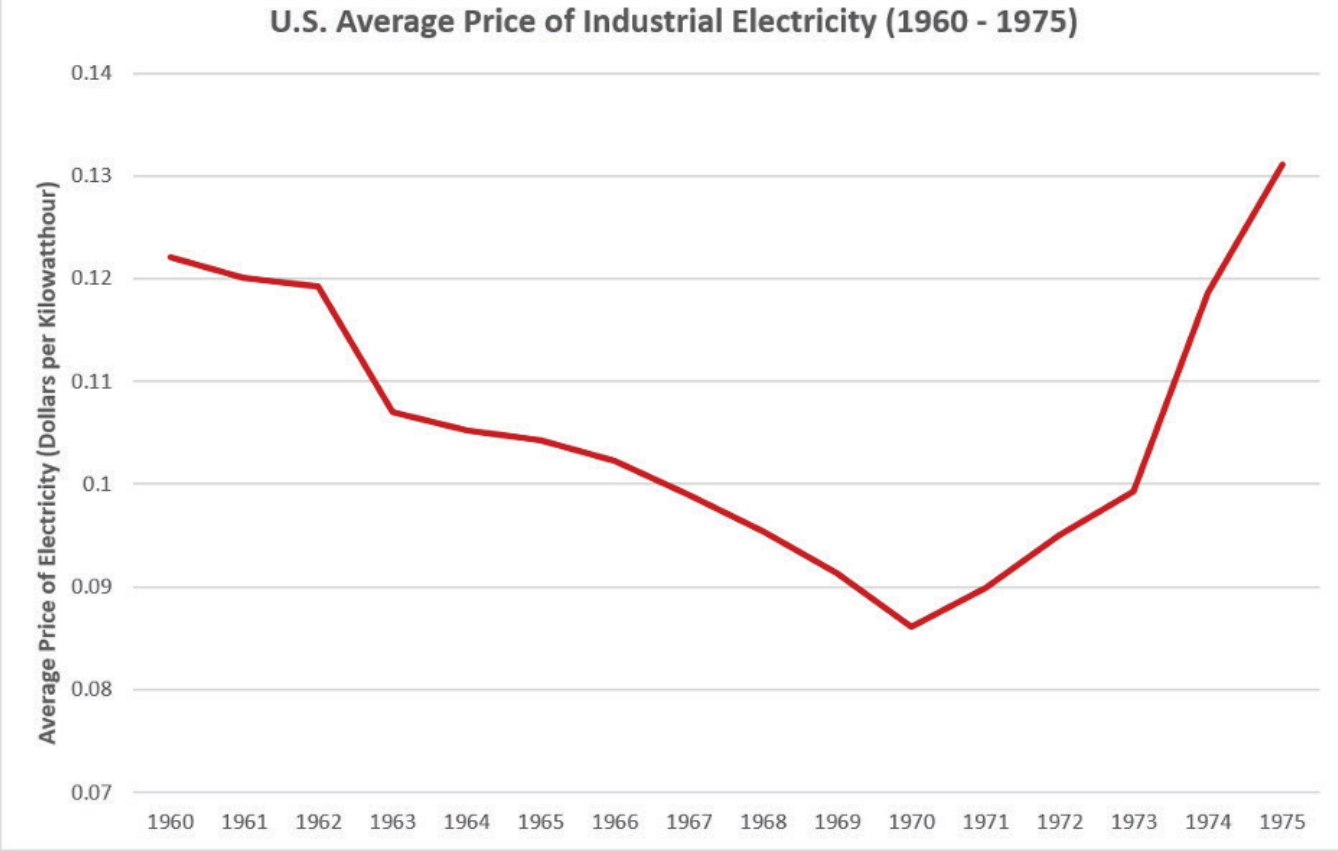
[7] D.Schlissel, D. Wamsted, "Small Modular Reactors: Still Too Expensive, Too Slow and Too Risky," Institute for Energy Economics and Financial Analysis" (2024). *https://ieefa.org/resources/small-modular-reactors-still-too-expensive-too-slow-and-too-risky*

[8] Such an effort may be impeded by advocacy from vested interests. Climate science today, for instance, faces the same "merchants of doubt" strategy that successfully kept the truth about the deleterious effects of cigarette smoking from the public for 50 years. See, N. Oreskes and E. Conway, Merchants of Doubt, Bloomsbury Press, June 2010). *https://www.merchantsofdoubt.org/*

[9] L. Geri and D. McNabb, Energy Policy in the U.S., at 64 (CRC Press 2011). The U.S. flared trillions of cubic feet of gas.

[10] J. Lesser and L. Giacchino, The Fundamentals of Energy Regulation, pp. 4-5, Public Utilities Reports Inc. (2007).

FIGURE 1
U.S. AVERAGE PRICE OF ELECTRICITY IN 2026 DOLLARS (1960-1975)



U.S. average cost of electricity (in 2026 dollars/kWh), industrial users. Source: Energy Information Administration. [11]

The era of energy abundance ended in the 1970s. It began with massive downward reserve revisions by Texaco, Inc. and other producers in 1970 – 1971 and was followed in 1973 by an oil embargo by the Middle Eastern oil producing cartel OPEC.[12] As the gap between oil and gas supplies and demand continued to widen, prices skyrocketed, and U.S. economies suffered. Legacy industries of the Midwest, especially in Ohio, suffered from what has been called the "high price fuel syndrome" – a cycle where consumers pay more for necessities like energy and food, forcing a cut to discretionary goods and services.[13] The effects on Ohio were severe: a loss of jobs, failed businesses, deferred infrastructure maintenance, decreased tax revenue and declining property value – all leading to the urban blight that has since been identified with "rustbelt economies." Policy makers in Ohio and other industrial states have ever since been eager to find ways to escape the pathologies of the rustbelt.

[11] Data from "U.S. Energy Information Administration - EIA - Independent Statistics And Analysis." n.d. *https://www.eia.gov/totalenergy/data/browser/index.php?tbl=T09.08#/?f=A&start=1960&end=2025&charted=0-1-2-3-4.*

[12] The Organization of Petroleum Exporting Countries was founded in Baghdad, Iraq, in 1960. The oil embargo was in response to U.S. support for Israel in the Yom Kippur War in October 1973.

[13] G. Tverberg, "High-Priced Fuel Syndrome," Our Finite World, September 26, 2012, *https://ourfiniteworld.com/2012/09/26/high-priced-fuel-syndrome/*

One promising response to the energy crisis was to invest in nuclear power. Although nuclear power had excited the imaginations of policy makers since the end of WW II, the industry had not begun in earnest until 1964 when President Lyndon B. Johnson signed the Private Ownership of Special Nuclear Materials Act. Utilities embraced nuclear energy as "the fuel of the future," and as the culmination of the march toward supersized generation facilities.[14] By 1971, there were twenty-two commercial power plants in full operation, generating about 2.4% of the U.S. electricity at the time.[15] The energy crisis of the 1970s stimulated an aggressive expansion of nuclear power plants.[16] By 1983, nuclear power was producing more electricity than natural gas; by 1984, nuclear power surpassed hydro-electric power, producing 14% of the nation's electricity, second only to coal.

Ohio's first nuclear plant, Toledo Edison's Davis-Besse Nuclear Power Station in Oak Harbor, commenced construction in 1970, before the energy crisis. However, when the Cleveland Electric and Illuminating Company (CEI) began construction in the 1970s on its 1300 MW Perry, Ohio Nuclear Power Plant, the energy crisis had fully gripped Ohio. The Perry plant construction was plagued by delays, especially after the 1979 Three-Mile Island partial reactor meltdown in Pennsylvania made it clear that more careful regulation was necessary for new nuclear power plants. In 1986, after a decade of delays, Perry became the 100th nuclear power plant in operation in the U.S.[17]

Ohio had plans for one other nuclear power plant: the William H. Zimmer Power Station in Moscow, Ohio, proposed by Cincinnati Gas and Electric. Construction began on that plant in 1972 and was expected to cost $480 million. By the time the project was abandoned in 1984, anticipated costs of completion had ballooned to $10 billion. Sunk costs

FIGURE 2
THREE-MILE ISLAND NUCLEAR PLANT SITE[18]



FIGURE 3
DAVID-BESSE NUCLEAR POWER PLANT, OAK HARBOR, OHIO[19]



Photo: Nuclear Regulatory Commission

[14] Lesser, supra, at 5.

[15] "The History of Nuclear Energy," *https://www.energy.gov/ne/articles/history-nuclear-energy*

[16] "Nuclear Power and Energy Security," Dec. 2024. World Nuclear Association. *https://world-nuclear.org/information-library/economic-aspects/nuclear-power-and-energy-security*

[17] "The History of Nuclear Energy," supra.

[18] U.S. Nuclear Regulatory Commission. (2012, June 27). Three Mile Island Nuclear Station [Photograph]. Flickr. *https://www.flickr.com/photos/nrcgov/7447159864/*

[19] U.S. Nuclear Regulatory Commission. (2011, December). [Davis-Besse Nuclear Power Station, Unit 1] [Photograph]. Flickr. *https://www.flickr.com/photos/nrcgov/6521259767/*



FIGURE 4
PERRY, OHIO NUCLEAR PLANTS[20]



upon abandonment were $1.6 billion. Half of these costs were passed through to ratepayers.[21]

As utilities scaled up to larger, more complex facilities, costs escalated and construction timelines expanded. As CEI experienced with Perry, original projections of five to seven years turned into ten to fifteen years, and sometimes more. The cost overruns, plant cancellations and stranded costs in Ohio and elsewhere engendered a regulatory legacy that continues to this day, fifty years later.[22]

The consequences were severe. Several utilities faced near-bankruptcy or outright insolvency. Public Service Company of New Hampshire declared bankruptcy due to financing difficulties associated with the Seabrook nuclear plant. The Washington Public Power Supply System defaulted on $2.25 billion in municipal bonds — at the time the largest municipal bond default in U.S. history — after abandoning four of five planned nuclear plants. The Washington Public Power Supply defaults and cost overruns at plants such as Diablo Canyon became touchstone examples of how vertically integrated utility regulation had failed to discipline capital investment decisions.[23]

For ratepayers who remained captive to utilities with nuclear plants, the consequences manifested as "rate shock" — sharp rate increases as nuclear construction costs were absorbed into the rate base. Rate increases of 50 to 100 percent over five-year periods were not uncommon in states with heavy nuclear construction programs.[24] By 1983, residential rates in Ohio had reached $0.25/kWh, in 2026 dollars – nearly double what electricity costs today. This rate shock catalyzed consumer interest in competitive electricity markets.

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[20] Photo: U.S. Nuclear Regulatory Commission, Perry Nuclear Power Plant, Unit 1, Flickr, *https://www.flickr.com/photos/nrcgov/6517603261/.* The photo was taken on November 20, 2007; uploaded to Flickr on December 15, 2011.

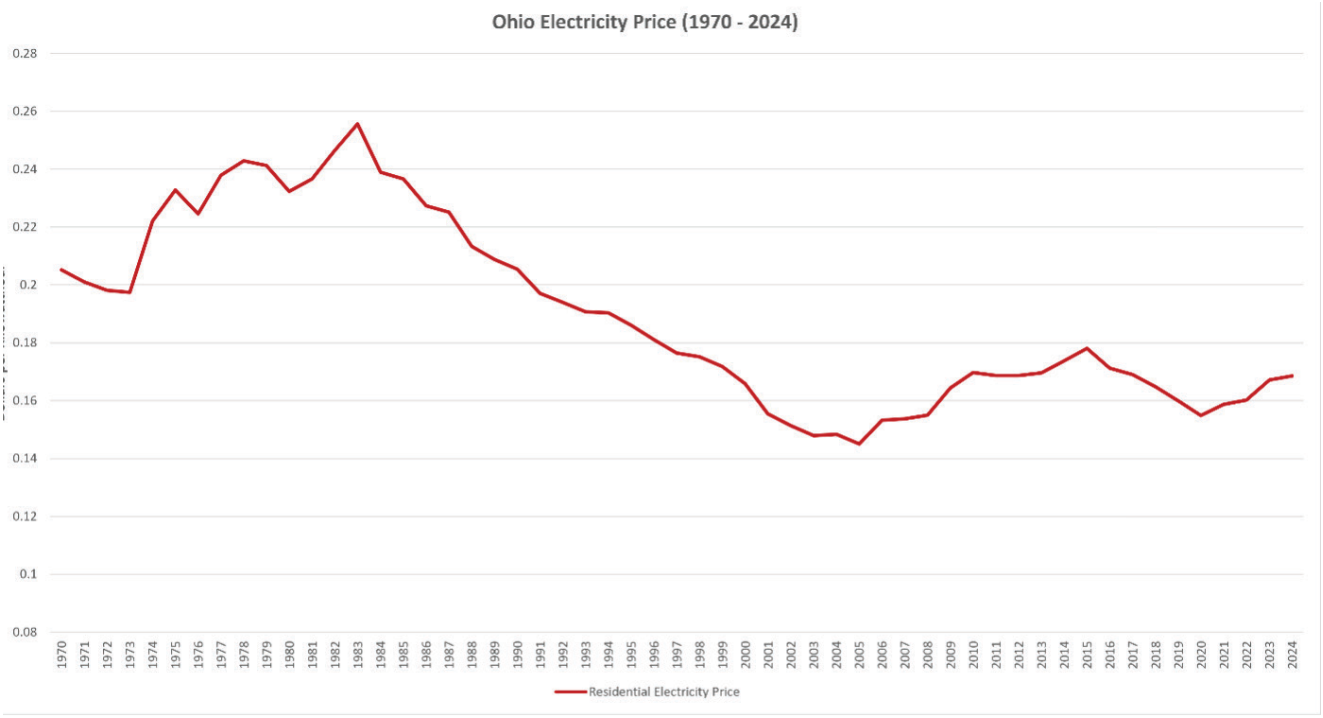
[21] The Zimmer station was eventually built as a coal-burning plant that began operations in 1991. That plant operated until 2022, when it was shut down by its owner, Vistra Corporation. For a detailed history of the Zimmer plant and its problems, see A. McClanahan, Zimmer: The Movement that Defeated a Nuclear Power Plant, University Press of Kentucky (2025).

[22] Lesser, supra, at 5.

[23] Pope, D. (1990). The Washington Public Power Supply System and Organizational Failures. Business and Economic History, 19, 74–82

[24] Data from "U.S. Energy Information Administration State Energy Data System." n.d. *https://www.eia.gov/state/seds/.*

FIGURE 5
OHIO RESIDENTIAL ELECTRICITY PRICES 1970-2024 ($2026)



Note rapid cost increases from 1974-1982 for electricity. Electricity prices decreased with falling natural gas prices after 1983. Source: Energy Information Administration.[25]

1.3 Regulation of Electricity in Ohio.

1.3.1 Post-WWII Vertically Integrated Regulatory Model.

Ohio's experience with nuclear power generation has spanned multiple regulatory eras over 50 years. The initial regulatory era was developed after the Public Utility Act of 1935 and was in place during the post war energy abundance period through 1999.[26] Regulatory oversight during this era followed the "vertically integrated model," pursuant to which investor-owned utilities recovered capital and other costs through state-supervised rate base proceedings that, in theory, assigned those costs only to the customers who benefited from them.

In the late 1800s, the United States Supreme Court had designated electricity as an industry "affected with a public interest" – that is, an industry so important to its citizens that the markets could not be left to the vagaries of an unfettered marketplace. Public Utilities operating in this space traded their right to compete in an open market in exchange for regulated monopoly control over that market, with the promise of a "fair rate of return" on its investments. That rate of return was set by state or federal regulatory agencies. The goal in setting the rate of return under this plan was to "mimic a competitive market outcome." [27] Under this model, all costs of operating the Public Utility are recouped, plus a reasonable profit on investment, from the

[25] Id.

[26] Lesser, supra at 4.

[27] Id. at 27.

cost of original generation to the ultimate delivery of electrons to end users. Such all-encompassing regulation is considered by economists to be "vertically integrated."[28]

For much of the mid-twentieth century, this system functioned relatively effectively because the underlying assumptions of the regulatory model largely held true.[29] Electricity demand grew consistently for decades as industrial production expanded, suburban development accelerated, and households adopted increasingly electricity-intensive appliances and technologies. At the same time, the economics of generation strongly favored larger centralized power plants. Large facilities could produce electricity at lower average costs than smaller generators because their high fixed costs could be spread across a rapidly growing customer base. The development of large, interconnected transmission grids also improved reliability and allowed utilities to share reserve capacity across regions. Under these conditions, vertically-integrated monopoly utilities were often able to reduce average electricity costs over time while still earning stable returns for investors.

So long as demand grew and economies of scale improved, this regulatory scheme worked. Utilities could keep building more generation and grid without increasing costs to ratepayers. But by the 1970s, energy abundance had disappeared, and the inefficiencies in this model began to show. Electricity demand growth slowed following the rapid surge in oil prices and broader economic stagnation of the decade, undermining utility forecasts that had assumed continued rapid increases in consumption.

At the same time, inflation and rising interest rates increased the cost of constructing large generating facilities. These pressures were particularly severe for nuclear power plants, many of which experienced significant delays, escalating safety requirements, and financing costs that far exceeded initial projections.

Public Utilities, with no incentive to constrain their costs or the risks to the ratepayers, nevertheless continued to build more large generation facilities, including nuclear plants. This inevitably led to what economists called "rate shock" – a rapid rise in the cost of electricity that destabilized the economy. See Figure 1. Because utilities earned returns based upon the size of their capital investments, critics also argued that the regulatory system itself encouraged excessive investment in large-scale infrastructure projects.

In Ohio, these tensions became particularly salient in projects such as the William H. Zimmer Power Station, which was originally planned as a nuclear facility before spiraling construction costs ultimately led to its conversion into a coal-fired plant.[30] Similar concerns emerged surrounding the costs associated with the Davis–Besse Nuclear Power Station and Perry Nuclear Power Plant. These projects raised increasingly contentious questions about whether ratepayers should bear the costs of poor business decisions by utilities.

By the 1980s, nuclear power generation had been identified as the principal underlying cause of rate shock. Nuclear cost overruns, prudency issues, and the perceived unfairness of captive ratepayers absorbing contractor mistakes gave rise to a national movement toward competitive electricity markets.

---

[28] Id. at 42. Under traditional regulatory principals, "Good Utility Practice" required that the investment was (1) prudent, (2) used and useful, and (3) known and reasonable. Regardless of hindsight, if the facility is abandoned before it ever produces electricity, it cannot pass the "used and useful" test. As a result, some investments into "stranded assets" were not recoverable. Utilities and regulators also rely on the "just and reasonable" principle. There is an unwritten rule that governs cost recovery for establishing regulated prices, known as the "regulatory compact." Under this rule, the regulator grants the utility a protected monopoly (sometimes called a franchise) for the sale of electricity in a defined service territory. In exchange, the utility commits to supply the full requirements of electricity for the customers in that territory at a price calculated to recover all operating expenses plus a "reasonable" rate of return on the capital invested. The regulatory compact and the just and reasonable standard together form the foundational basis for rate regulation.

[29] Karl A. McDermott, Cost of Service Regulation in the Investor-Owned Electric Utility Industry: A History of Adaptation (Washington, DC: Edison Electric Institute, 2012), vii–viii, 17–18. *https://www.ourenergypolicy.org/wp-content/uploads/2012/09/COSR_history_final.pdf*

[30] New York Times, "Nearly Completed Nuclear Plant Will be Converted to Burn Coal," January 22, 1984. Available online: *https://www.nytimes.com/1984/01/22/us/nearly-completed-nuclear-plant-will-be-converted-to-burn-coal.html*



1.3.2 DEREGULATION OF NATURAL GAS AND THE RISE OF ELECTRICITY DEREGULATION.

Prior to the 1970s, most natural gas in the United States was a byproduct of oil production. If there was no market for that gas, it was simply flared. Unlike for oil, natural gas was difficult to store or transport to a market. So much gas was being flared that by the mid-1970s the oil and gas industry had developed a natural gas pipeline system to gather, transport and distribute natural gas to markets – initially for industrial consumption, but eventually for electricity generation and home heating. Federal price controls put onto natural gas during the energy crisis kept companies from drilling directly for gas, and as oil deposits were depleted, so were the byproduct gas supplies.

In 1978, the U.S. had passed a series of natural gas price decontrols to encourage new drilling for natural gas. It was highly successful in reversing the shortage of natural gas that had developed in the 1970s. The Federal Energy Regulatory Commission (FERC) followed this price decontrol with a series of landmark rules that opened access to all new production to the interstate pipelines. The result was the creation of wholesale commodity markets for natural gas that were highly competitive and which eventually brought natural gas prices down from their mid-1980s peaks. Utilities could build natural gas-fired power generation quickly and cheaply. In Ohio, where coal was still king, this initially meant the addition of peaking units.

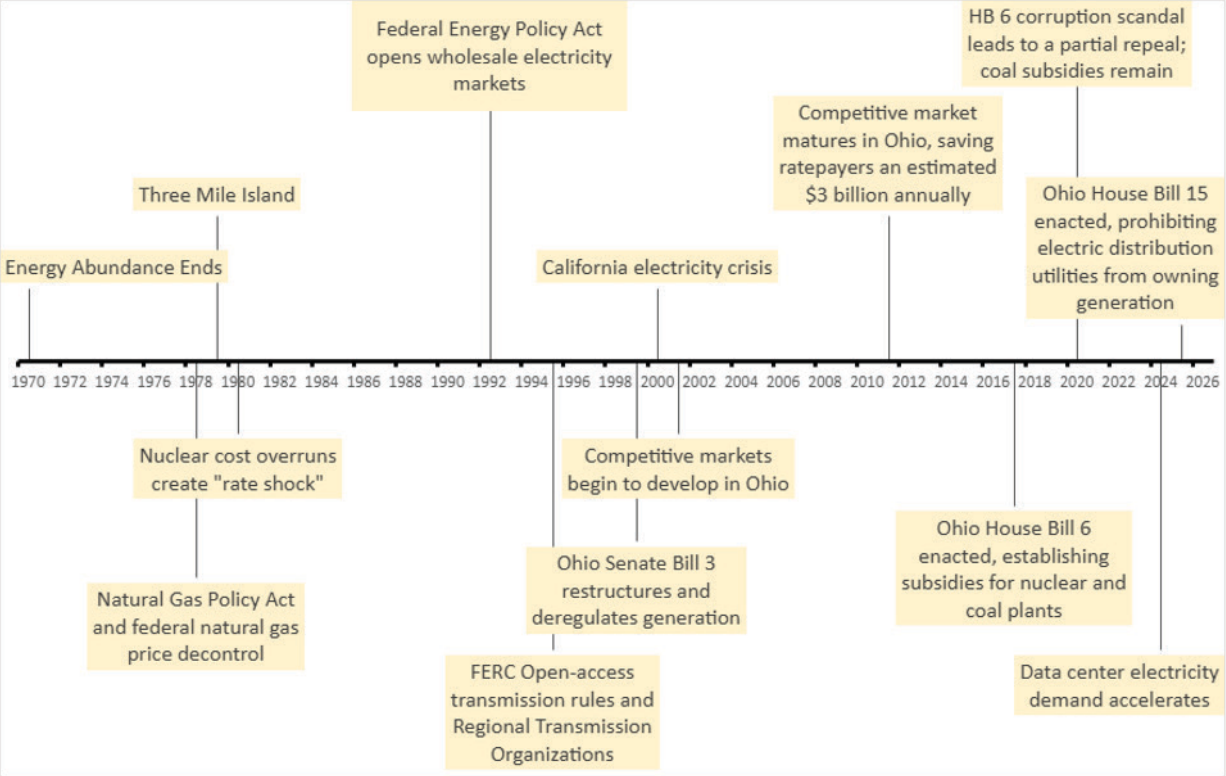
The deregulation of natural gas worked so well that by the 1990s manufacturers and other industrial users began to ask if the electricity industry might not also be deregulated in a similar manner. The U.S. Energy Policy Act of 1992 created the first opportunities for wholesale electricity providers to directly supply large industrial users. Independent utilities began building lower cost natural gas power generation. By directly accessing wholesale markets, the end users were able to avoid the nuclear power cost overruns. This in turn led the California legislators to restructure the state's electricity regulatory rules in 1998 to allow end users to access these wholesale markets.

1.3.3 OHIO DEREGULATES ELECTRICITY

The California experiment in electricity deregulation did not go well. Using retail price caps, the state sought to protect ratepayers from large swings in prices while wholesale markets developed. This led to utilities buying wholesale power at prices that at times exceeded the retail sale price they could receive for the power. That, together with market manipulation by Enron (an energy trading company), led to financial chaos and one of California's public utilities becoming insolvent. By 2000, California was overwhelmed by electricity shortages and sky rocketing prices, and by 2002 it had returned to a vertically integrated regulatory model.[31]

[31] Under California law, a utility may own local transmission, distribution and generation. But transmission and generation are operated by the California Independent System Operator. See, Pechman, Carl. "California's Electricity Market A Post-Crisis Progress Report. Public Policy Institute of California" California Economic Policy, vol. 3, no. 1, Jan. 2007.

FIGURE 6
TIMELINE OF NUCLEAR POWER DEVELOPMENT AND DEREGULATION OF ELECTRICITY IN OHIO



Notwithstanding this result, other jurisdictions that deregulated, most notably in the United Kingdom, were having success. The result was that a handful of U.S. states proceeded with restructuring electricity markets. Ohio was one of the states.

Prior to 2001, Ohio utilities recovered all their costs based upon an "allowed rate of return" model, which they passed through to ratepayers' capital costs, operating expenses, fuel costs, taxes and charges on debt and equity financing. In addition to recouping these costs, the utility also received a "reasonable" rate of return on its capital investments, typically between 9-11%. This structure provided utilities with a powerful incentive to over-invest in capital, with a bias specifically toward building large, capital-intensive generation assets.

Utilities building nuclear power plants set the standard for this behavior. According to Idaho National Labs, cost overruns for nuclear plants were about 137% before the 1979 accident at the Three-Mile Island plant in Pennsylvania. Since 1979, they have averaged around 285.8%,[32] directly leading to the national "rate shock" crisis. By the mid 1980s, the real cost of industrial electricity in Northern Ohio was over $0.15/kWh; the real cost of residential power over $0.25/kWh. In addition, Ohio was losing industry and manufacturing jobs to states with more competitive electricity prices.[33]

The success of natural gas and telecommunications deregulation pushed legislators in states with high electricity costs to consider deregulating the

[32] Guaita, N., Spangler, R., & Hansen, J. (2024). Parametric and nonparametric models of U.S. cost overruns for nuclear power plants. Pacific Basin Nuclear Conference 2024 (PBNC), 142–151. https://doi.org/10.13182/pbnc24-45155

[33] See, e.g. Kiesling, L.L. (2009). Deregulation, Innovation and Market Liberalization: Electricity Regulation in a Continually Evolving Environment. Rutledge Studies in Business Organizations and Networks, 24-25.

generation side of electricity as a way to constrain costs. The Energy Policy Act of 1992 was followed by FERC ordered open transmission rules, and the creation of Regional Transmission Organizations.

In 1999, the Ohio General Assembly passed Ohio Senate Bill 3 that went into effect in 2001. This bill restructured electricity markets over time, unbundling the distribution and transmission service from the generation service. As part of the restructuring, ratepayers in Northern Ohio were required to pay FirstEnergy nearly $7 billion for its "stranded assets" – including portions of its nuclear facilities that had been rendered uneconomic by competition.[34]

It took another ten years and more regulatory restructuring for Ohio to transition to a functioning competitive generation market. But eventually, competition took hold. Prices for generation came down significantly, principally due to cheap natural gas from shale development in Pennsylvania and Ohio. The new deregulated market enabled the majority of ratepayers in Ohio to access the lower cost generation.

A study by Cleveland State and Ohio State Universities found that Ohio ratepayers saved an average of nearly $3 billion/year between 2011-2015 as a direct result of the restructured and deregulated electricity markets.[35] Subsequent studies have demonstrated savings of an average of $2.7 billion yearly through at least 2024. Cleveland State estimated that deregulation of retail electricity markets had delivered over $37 billion in savings to Ohio customers between 2011-2024.[36]

These savings have had a significant impact on Ohio's economy and have served to attract and retain industry. Commercial and industrial users have saved an average of over $0.02/kWh since 2011 (2023 dollars). Around 75-80% of end users shop for their electricity, including residential users. The annual savings have averaged $54,840 for industrial, $1,492 for commercial and $261 for residential users.[37]

TABLE 1
TOTAL SAVINGS DUE TO DEREGULATED ELECTRICITY GENERATION MARKETS IN OHIO
(millions of dollars)

Year	Total
2011-2018	$21,278
2019	$2,725
2020	$2,612
2021	$2,714
2022	$2,734
2023	$2,702
2024 (est.)	$2,749
Total	$37,513

Amounts are in 2023 dollars.
Source: Cleveland State University Energy Policy Center (2024).

TABLE 2
TOTAL SAVINGS PER KWH BY SECTOR IN OHIO SINCE 2011 DUE TO DEREGULATION
(millions of dollars)

End-Use Sector	Savings Rate ($/kWh)
Residential	$0.0251
Commercial & Industrial	$0.0201

Amounts are in 2023 dollars.
Source: Cleveland State University Energy Policy Center (2024).

The value of deregulation in Ohio is particularly striking when comparing deregulated to regulated states in the Midwest. Group average electricity prices show that electricity costs continue to come down in Ohio, Illinois and Pennsylvania, while going up in Michigan, Wisconsin and Indiana (see figure 7).

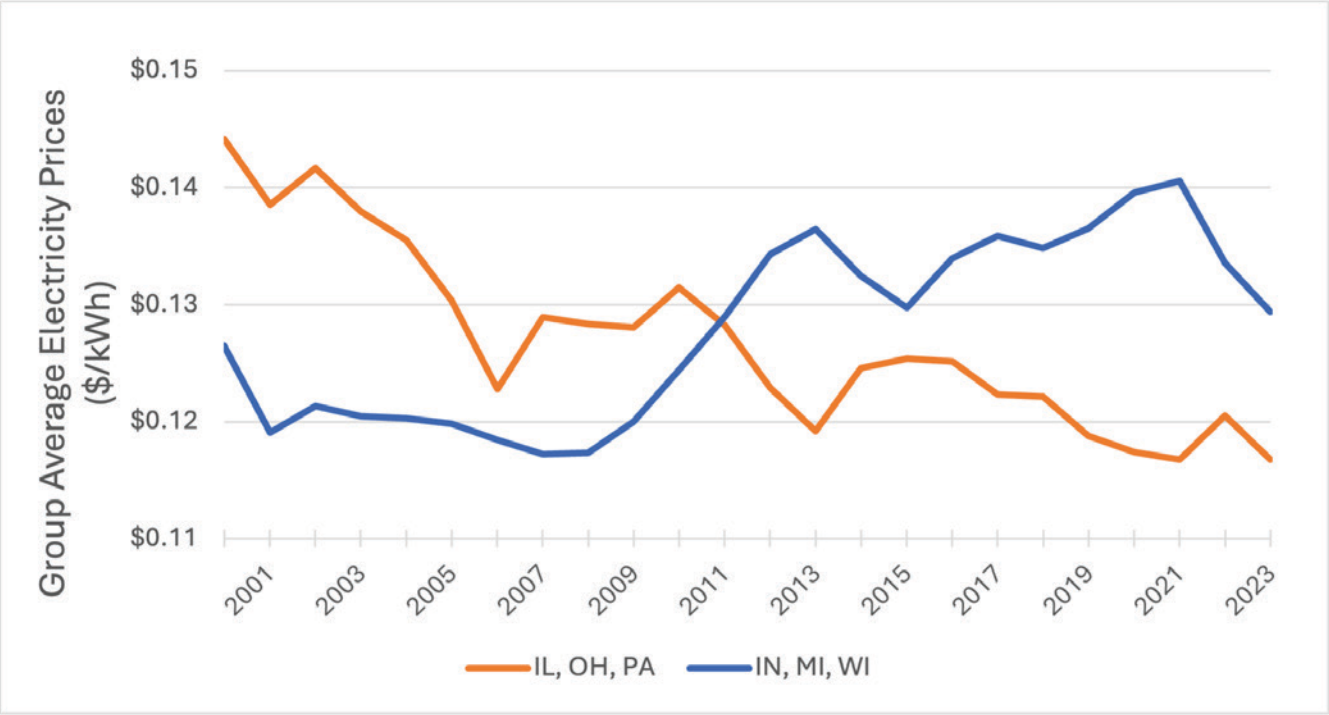
[34] The PUCO approved FirstEnergy's transition plan for its Ohio companies in 2000. See *https://www.sec.gov/Archives/edgar/data/20947/000095015204007903/l10407ae10vq.htm.*

[35] Thomas, A.R., et al. Energy Policy Center, Cleveland State University. (2018). Electricity customer choice in Ohio: How competition has outperformed traditional power regulation. *https://engagedscholarship.csuohio.edu/urban_facpub/1416*

[36] Thomas, A., & Henning, M. (2024). 2024 update on electricity customer choice in Ohio: Deregulated markets continue to save Ohio ratepayers nearly $3 billion per year. Energy Policy Center, Maxine Goodman Levin School of Urban Affairs, Cleveland State University. *https://engagedscholarship.csuohio.edu/urban_facpub/1859/*

[37] Id.

FIGURE 7
AVERAGE TOTAL ELECTRICITY PRICES IN ALL SECTORS IN SIX MIDWESTERN STATES 2000-2023



Real 2023 dollars. Source: Cleveland State University Energy Policy Center (2024).

1.3.4 OHIO HOUSE BILL 15 AND THE RISE OF DECENTRALIZED POWER GENERATION

Over the years, Ohio utilities have sought to return to vertically integrated regulation, at least in part. These efforts culminated in Ohio House Bill 6, passed in 2017, which required ratepayers to subsidize nuclear and coal-fired generation to ensure that they would be competitive with natural gas and renewable power. After it was later discovered that FirstEnergy Corporation had bribed members of the General Assembly to pass the legislation[38], the bill was repealed, in principal part, in 2021. The coal subsidies, however, survived until 2025.

During this time period, utilities were also discovered to be improperly accounting for generation costs as distribution costs, thereby placing those costs into the distribution rate base.[39] In 2025, these problems eventually led the Ohio General Assembly to pass House Bill 15. HB 15 requires that electric distribution companies may no longer own generation. This appeared to end – at least briefly – the era of utility efforts to seek Ohio ratepayer subsidies for distribution company-owned generation in Ohio.

HB 15 did more, however, than end cross-subsidization. HB 15 enabled users to build generation facilities off site, connecting them to their operations, and still have the facilities treated as "behind the meter." This in turn has made it more cost effective to build distributed generation, especially in those instances where the end users can net meter, such as for solar power or natural gas-based fuel cells. This also provides a check on rising distribution system costs; ratepayers can seek relief from rising distribution costs by generating their own power onsite, behind the meter. It remains to be seen how much new generation this will create, but local distributed generation appears to be growing in popularity as an alternative to the grid.[40]

[38] Wamsley, Laurel. "Ohio House Speaker Arrested In Connection With $60 Million Bribery Scheme." NPR, 21 July 2020, *https://www.npr.org/2020/07/21/893493224/ohio-house-speaker-arrested-in-connection-to-60-million-bribery-scheme*.

[39] In re Application of Ohio Edison Co., The Cleveland Electric Illuminating Co., & The Toledo Edison Co. for Authority to Provide for a Standard Service Offer Pursuant to R.C. 4928.143 in the Form of an Electric Security Plan, 2019-Ohio-5199 (Ohio Dec. 23, 2019)

[40] See, e.g. https://dam.assets.ohio.gov/image/upload/puco.ohio.gov/empliibrary/files/DER/For%20Web/2025_DER_Summary_FINAL.pdf (growth in residential generation interconnections in Ohio).

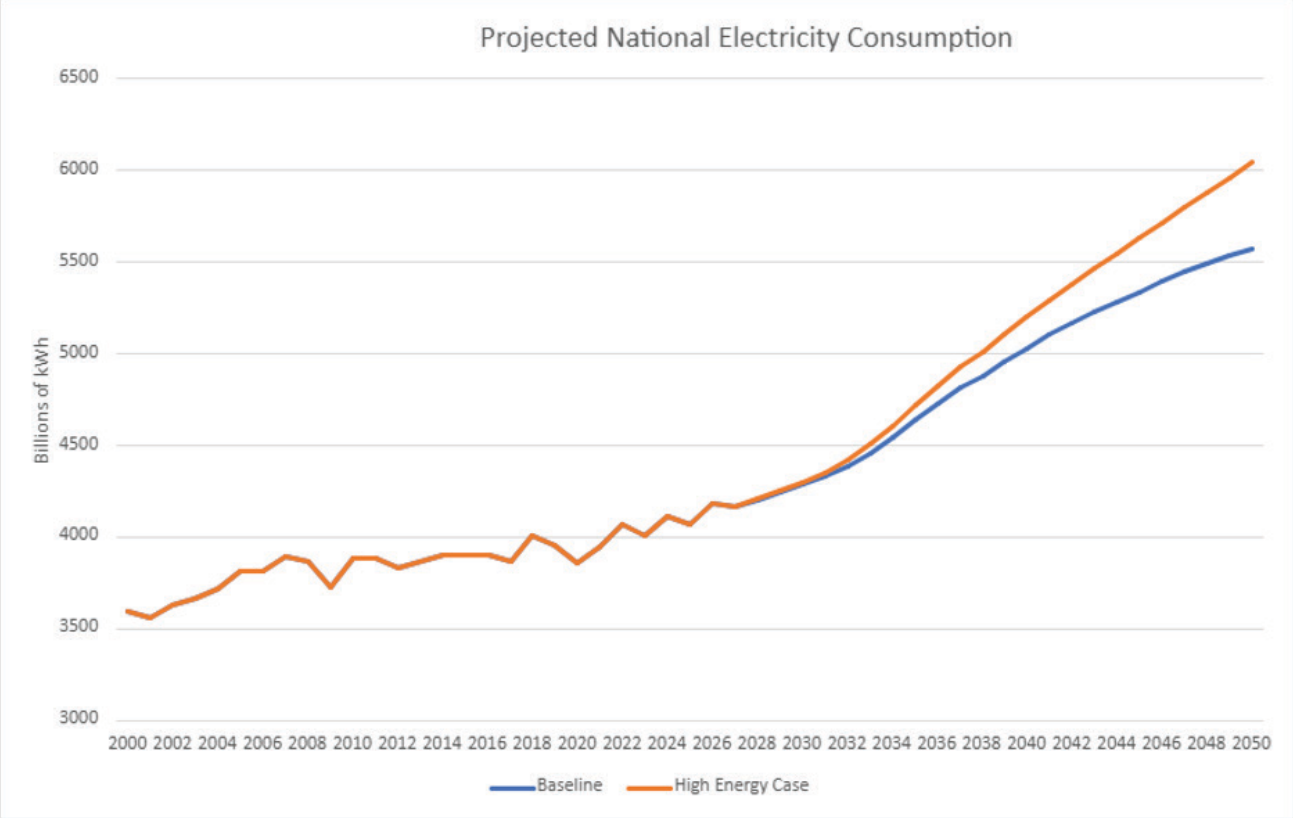
1.4 CALLS FOR ADDITIONAL GENERATION AND NUCLEAR POWER IN OHIO

1.4.1 CONCERNS OVER GROWING ELECTRICITY DEMAND IN OHIO

Over the past 20 years, electricity demand in the U.S. had been flat, due in part to innovations and in part to economic headwinds, including a downturn in domestic manufacturing.[41] Now, however, the Department of Energy (DOE) is anticipating that electrification, expansion in data centers, and new domestic manufacturing could lead to demand growing by 15% in the coming decade (from around 4.2 to 4.8 terawatt-hours (see figure 8)). Some experts have suggested that overall, U.S. demand could increase by 9% in the next five years.[42] If insufficient new, low-cost generation is built to meet this demand, prices may go up.

Data centers appear to be driving the anticipated near-term demand growth. According to a study by Goldman Sachs, the AI revolution is likely to drive up data center demand 160% by 2030.[43] Data center energy demand world-wide is projected to grow from around 1-2% of all power consumed to around 3-4%

FIGURE 8
U.S. ANNUAL ELECTRICITY CONSUMPTION FROM 2000, PROJECTED TO 2050



U.S. Annual Electricity Consumption from 2000, and projected to 2050, with business as usual and high energy use case. Source: Energy Information Administration. [44]

[41] "Clean Energy Resources to Meet Data Center Electricity Demand," Department of Energy Office of Policy, August 12, 2024. *https://www.energy.gov/policy/articles/clean-energy-resources-meet-data-center-electricity-demand*

[42] See, e.g. *https://www.icf.com/news/2024/09/icf-report-projects-surge-in-us-electricity-demand-by-2028*

[43] "AI Poised to Drive 160 Percent Increase in Power Demand," May 14, 2024, *https://www.goldmansachs.com/insights/articles/AI-poised-to-drive-160-increase-in-power-demand*

[44] The high energy consumption case is primarily driven by projected data center development. See "Total Energy Annual Data – EIA, accessed on July 27, 2026, from https://www.eia.gov/totalenergy/data/annual/. And "Annual Energy Outlook 2026. See also: "Annual Energy Outlook 2026," U.S. Energy Information Administration, U.S. Dept. of Energy. *https://www.eia.gov/outlooks/aeo/narrative/.*

of total power by the end of the decade. In the U.S., data centers used about 3% of overall power in 2022. By 2030, it is expected to be around 8%.[45]

If Department of Energy (DOE) projections are correct, the U.S. will need to find roughly 600 new terawatt-hours of power annually by 2036. Ohio is ranked 6th nationally in gross domestic product and 4th in electricity consumption, which is approximately 3.9% of the national load. If Ohio's share in the national consumption remains the same, Ohio would need an additional 23.4 TWhs of electricity annually by 2036. Indeed, Ohio has recently been the target of data center growth planning. AEP Ohio, for example, projects 15 GW of new load in its territory by 2030, driven by Amazon, Google, and other data centers.[46] The electric utility opened a proceeding before the Public Utility Commission of Ohio (PUCO) in May of 2024 seeking new tariffs designed for this increased load.[47]

Yet new generation is on the way to meet most of this demand. PJM reports that 811 new projects, with a maximum output of 220 GW of electricity, have applied to connect to the grid; additionally, PJM notes that 53 GW have completed the study process and are ready to be built, but are delayed due to factors "out of [their] control."[49] Narrowing the focus to Ohio, PJM reported to the Ohio Senate that as of January 15, 2026, 10.1 GW are in signed interconnection agreement, and 3.7 GW are in the study process (see figures 9 and 10).[50] Furthermore, as of 2026, Berkeley Labs has identified 16.8 GW of new generation interconnection requests for Ohio, along with 3.7 GW of new storage (see figure 11). It has further identified 99.8 GW of generation and 42.7 GW of storage overall for the PJM RTO footprint, all power that can be readily moved into Ohio markets.

We can compare the Department of Energy electricity consumption projection with the approved and proposed generation for Ohio. Using a conservative capacity production factor of 20% for the reported 10.1 GW in signed agreements,[51] we can calculate that it will produce about 75% of the projected increase in demand (10,100 MW·365 days ·24 hours/day · 0.20 ≈17.7 TWh annually). If we use the Berkeley snapshot of all generation in the queue for Ohio, along with the same 20% conservative estimate, 16.8 GW would produce about 29.4 TWh annually, which is about 125% of the projected increase in demand. In short, there appears to be ample generation already on the way to meet the anticipated Ohio demand, without new nuclear power.

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[45] According to the Electrical Power Research Institute, it could reach 9% by 2030. Id.

[46] *https://www.utilitydive.com/news/aep-data-centers-amazon-google-load-growth-epa/714806/*

[47] *https://www.utilitydive.com/news/aep-ohio-data-center-crypto-rates-puc/716150/*

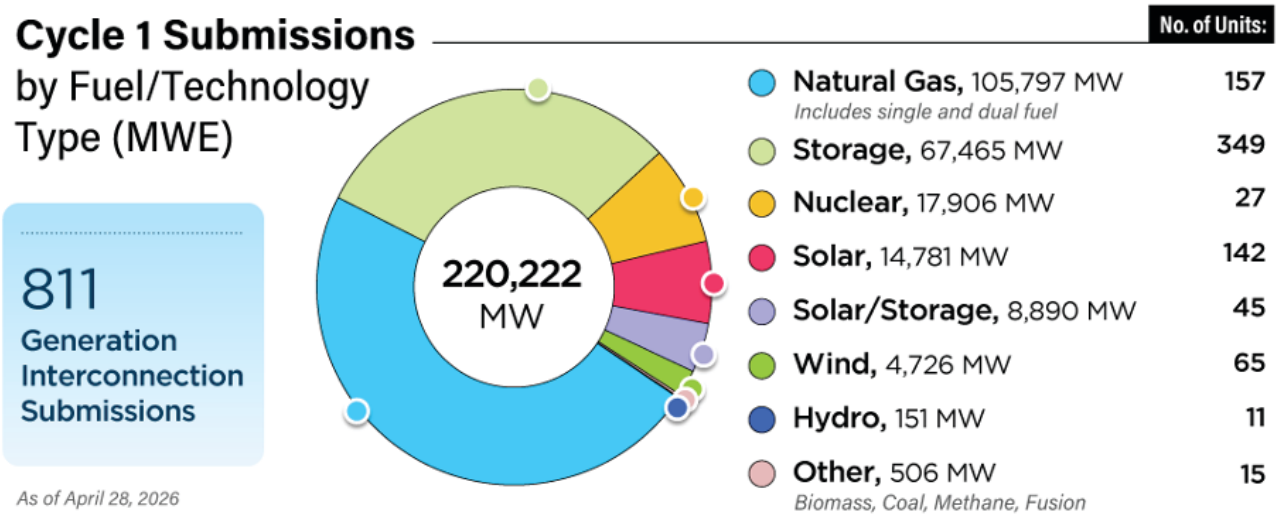
[48] PJM Interconnection. (2026, April 29). Over 800 new generation projects seek to connect under PJM's reformed process. PJM Inside Lines. *https://insidelines.pjm.com/over-800-new-generation-projects-seek-to-connect-under-pjms-reformed-process/*

[49] PJM Interconnection. Interconnection Reform Progress. Fact sheet, 2026. PJM. Accessed 6 Aug. 2026.

[50] PJM Interconnection. (2026, March 24). PJM: Taking Action to Secure Reliability and Affordability Amidst Historical Demand Growth [Written testimony]. Ohio Senate Energy Committee.

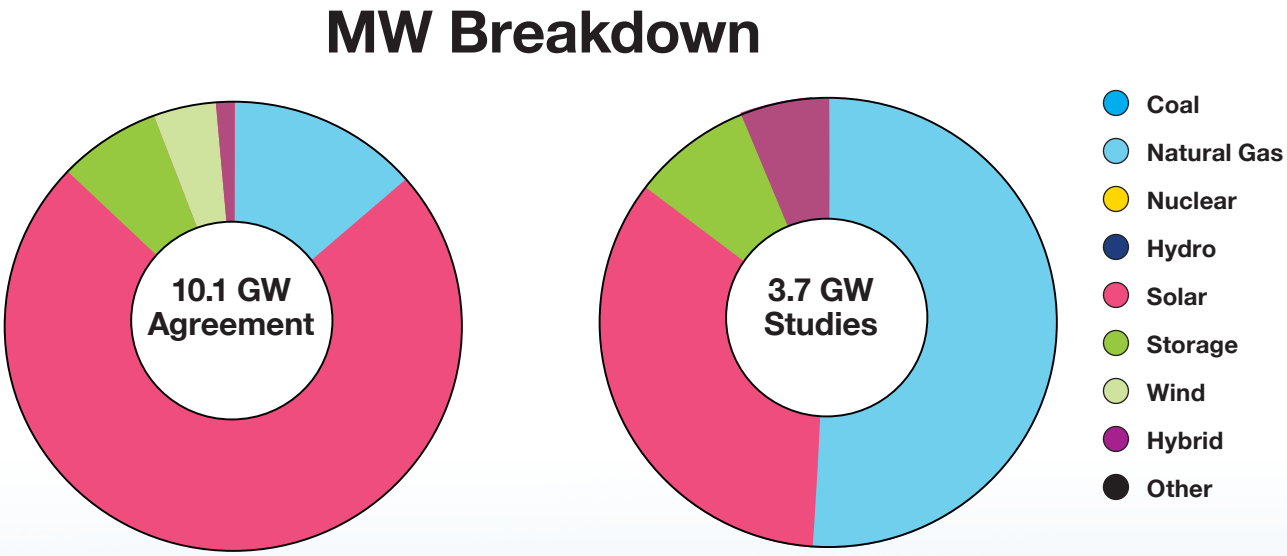
[51] The 10.1 GWs in signed agreements includes battery storage, which appears to be less than 10% of the capacity. However, this is offset by the conservative estimate of 20% capacity factor for natural gas and wind, which make up around 1/5th of the capacity.

FIGURE 9
TYPES AND AMOUNTS OF GENERATION INTERCONNECTION SUBMISSIONS IN PJM QUEUE 2026



Types of Generation Interconnection Submissions to PJM. Source: PJM Inside Lines [52]

FIGURE 10
PJM INTERCONNECT AGREEMENTS AND STUDIES AS OF JANUARY 2026.

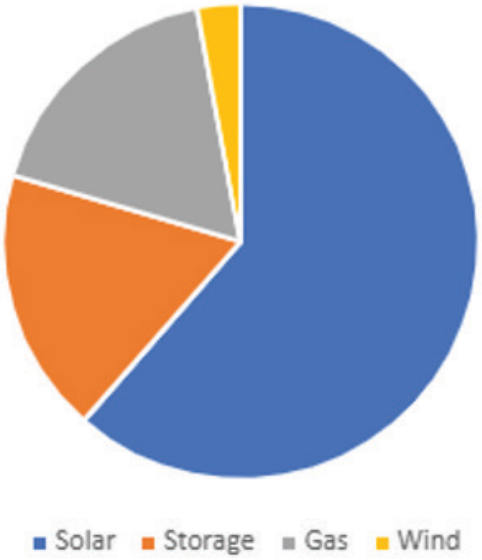


Construction Projects in Signed Agreement (10.1 GW) and Under Study (3.7 GW) in Ohio. Source: PJM presentation "PJM: Taking Action to Secure Reliability and Affordability Amidst Historic Demand Growth" at the Ohio Senate Energy Committee Hearing, March 24, 2026[53]

[52] McGovern, Jason. "Jason McGovern." PJM Inside Lines, 6 May 2026, insidelines.pjm.com/over-800-new-generation-projects-seek-to-connect-under-pjms-reformed-process/.

[53] Haque, Asim .Z. "PJM: Taking Action to Secure Reliability and Affordability Amidst Historic Demand Growth." Energy Committee Hearing, Ohio Senate, 24 March 2026, Ohio Statehouse, Columbus, Ohio. Slide Presentation. *https://ohiosenate.gov/committees/energy/meetings/cmte_s_energy_1_2026-03-24-1000_1211*

FIGURE 11
OHIO INTERCONNECTION REQUEST BY ENERGY SOURCE, END OF 2025

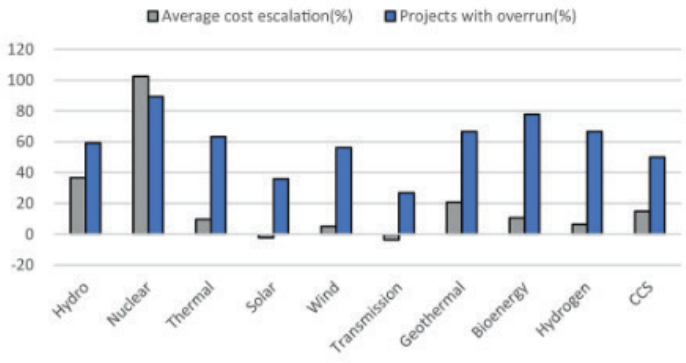


Current Ohio Interconnection requests show 16.8 GW new generation in the queue along with 3.7 GW storage. Source: Energy Markets & Planning Berkeley Lab[54]

1.4.2 ROLE OF NUCLEAR POWER IN MEETING NEW DEMAND

Advocates of nuclear power argue that it is the best long-term clean energy answer to meeting this new demand. However, it may not be able to build new plants without ratepayer subsidies. Nuclear power construction continues to experience the most cost overruns of all new generation. According to a study recently conducted by Boston University, power generation construction costs, in general, average overruns of around 40%. Nuclear power plants continue to be the worst offenders, with average construction cost overruns of 102%, or about $1.56 billion per facility more than expected.[55]

FIGURE 12
FREQUENCY AND MAGNITUDE OF COST OVERRUNS



Frequency and Magnitude of Cost Overruns of 662 Energy Infrastructure Projects from 1936 to 2024. Source: Sovacool and Hanee, Energy Research.[56]

Further, it is unclear that new nuclear power can be built timely to respond to the anticipated demand spikes. According to projections by AEP, new data center demand will occur over the next five years. The time frames for new nuclear plants are at a minimum of 7-10 years.[57] Some have argued that gas turbine could provide bridge power to meet the demand until the nuclear plants are built.[58] However, it remains unclear how the economics of this might work. Would utilities retire the natural gas plants? Would they no longer be "used and useful" and thereby be insusceptible to cost recoupment? Can the gas plants be decommissioned and profitably moved to another location?

Advocates further argue that there are promising new nuclear plant technologies known as Small Modular Reactors (SMR) that can resolve the problems with cost overruns and start up delays. SMRs are distinguishable from traditional forms of nuclear

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[54] Maps of active interconnection requests by region, state, and county | Energy Markets & Planning, accessed on August 7, 2026. *https://emp.lbl.gov/maps-projects-region-state-and-county*

[55] Sovacool, Benjamin K., and Hanee Ryu. "Beyond economies of scale: Learning from construction cost overrun risks and time delays in global energy infrastructure projects." Energy Research and Social Science, vol. 123, May 2025, p. 104057, *https://doi.org/10.1016/j.erss.2025.104057.*

[56] Id.

[57] American Electric Power Ohio. (2026). 2026 AEP Impact Report.

[58] A. Finan, et al, supra note 4.

power generation principally by their size: they are typically in the hundreds of MW in capacity, whereas traditional nuclear plants range from 500 to 2000 MW.[59] The notion is that economies of scale can be realized through manufacturing of modular "off the shelf" equipment that would be used to build the plants. As of the date of this Study, no SMRs have been installed in the United States, and of course no "off the shelf" market yet exists for modular equipment.

A recent study by the Institute for Energy Economics and Financial Analysis (IEEFA), however, concluded that there is little evidence so far that SMRs will be able to avoid the same problems that have plagued nuclear in the past. Their analysis, after reviewing the state of the technology, is that SMRs "still look to be too expensive, too slow to build, and too risky to play a significant role in transitioning from fossil fuels in the coming 10-15 years." [60] IEEFA notes that the current SMR installation cost estimates range from $10,000 to $20,000 per kW. The installed cost of the traditional nuclear plant by Georgia Power (Vogtle 3&4) likewise do not suggest costs are coming down – it cost over $20,000/kW (2023 dollars) to build.[61] Gas turbine, on the other hand, typically can be installed for around $1000/kW, while fuel cells are as low as $5000 installed.[62] Solar panels and wind turbines cost around $2000/kW to install. [63]

The "levelized cost of electricity" produced provides a more useful comparison, since it includes operating expenses, such as fuel costs (which for wind and solar are free). According to IEEFA, SMR power costs in 2030 will be between $89-$119/MWh, depending upon IRA subsidies. This compared to around $24/MWh for solar, $29 for wind, and $60 for solar + battery storage.[64] The Energy Information Administration (EIA) has made similar cost projections: by 2031, advanced nuclear power will be about $88/MWh with IRA subsidies. The EIA projects that in 2031 solar will cost $58/MWh, onshore wind $57/MWh, and combined cycle natural gas with carbon capture and sequestration $58/MWh.

In short, based upon the current industry cost projections for SMR, it is unlikely SMR generation will effectively compete with conventional gas-fired generation, fuel cells or with renewable power in the near term. The bet that policy makers must make is that in 30 years, as natural gas supplies dwindle, climate change worsens and the grid is saturated with intermittent renewable power, nuclear power will be ready and available to rescue ratepayers from an otherwise difficult energy predicament.

That bet might be well worth making. But how the bet will be made, and who pays for it, are important considerations today. There may be ways to accomplish this without undermining the competitive energy retail markets that have saved ratepayers $3 billion/year.

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[59] See, "Advanced Small Modular Reactors," Department of Energy. *https://www.energy.gov/ne/advanced-small-modular-reactors-smrs*

[60] Schlissel and Wamsted, IEEFA at 3, supra.

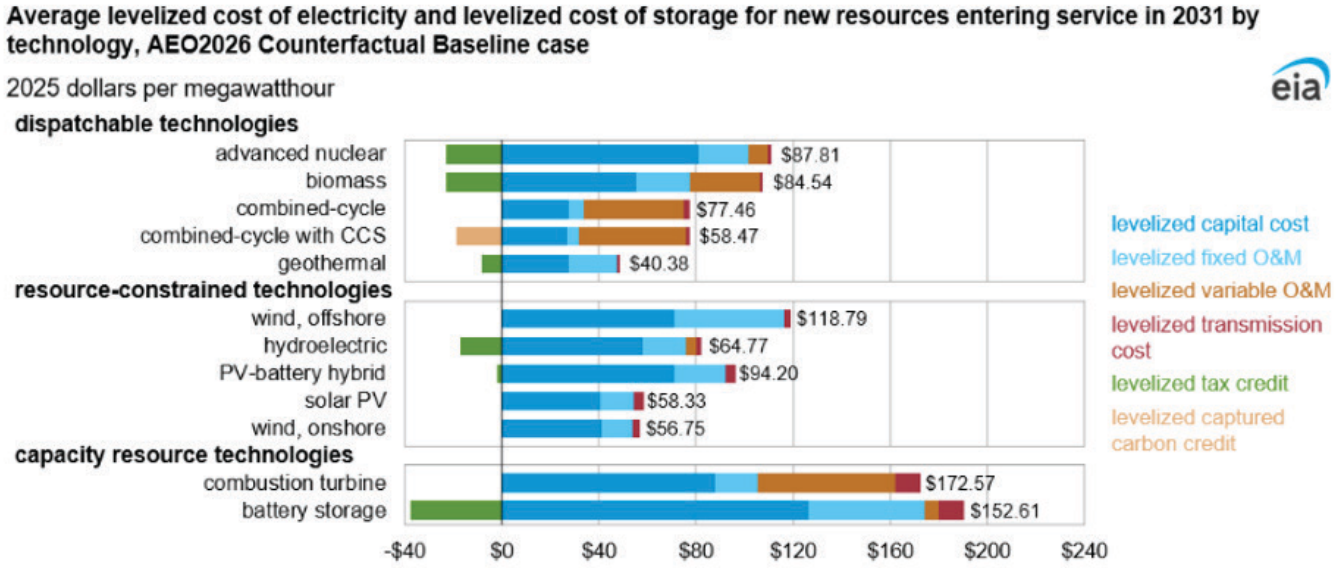
[61] Id. at 5 (citing NuScale, X-Energy and GE-Hitachi)

[62] Based upon proposals received for onsite generation at Cleveland State University (with IRA tax credits).

[63] *https://www.nlr.gov/solar/market-research-analysis/solar-installed-system-cost"*

[64] Schlissel and Wamsted, IEEFA, supra.

FIGURE 13
LEVELIZED COST OF ELECTRICITY AND STORAGE



Data source: U.S. Energy Information Administration, Annual Energy Outlook 2026

Note: The stated LCOE values include the levelized tax credit component for eligible technologies. CCS=carbon capture & sequestration, PV=photovoltaic, O&M=operations and maintenance

Levelized cost of electricity and storage for new energy resources entering service in 2031.[65]

1.4.3. PROPOSED OHIO LEGISLATION

Some members of the Ohio General Assembly have determined that new nuclear power in Ohio would be desirable. They have apparently also determined that it is unlikely to be built without subsidies from Ohio's ratepayers. As a result, they have proposed legislation (House Bill 862)[66] that will enable Ohio's distribution utilities to build, own and operate nuclear power plants.

That legislation carves out a notable exception to what, just a year ago with HB 15, had been made into law: the end of distribution utilities owning and operating generation. HB 862 seeks to mitigate the risk to ratepayers by requiring that the electric distribution company building the nuclear plant obtain 20 year "retail participation agreements" from end users for the early years of operations. These agreements, presumably, would ensure that some of the cost of the nuclear plant be borne by specific end users rather than socialized across a larger rate base. It is difficult to know from the current drafts of the bill exactly what costs can be passed through to ratepayers.[67] But the redactors of the bill clearly contemplate that Ohio's rate payers, one way or another, will bear the risk of cost overruns, above-market generation and environmental or decommissioning problems.

A stated goal of the legislators is to help Ohio reach or maintain "energy independence."[68] Ohio is part of the PJM Interconnect regional transmission organization, which means it readily imports and

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[65] Figure 13 from "Annual energy outlook 2026" *https://www.eia.gov/outlooks/aeo/narrative/*. Levelized cost of electricity and storage is calculated by LCOE = ((fixed charge factor *capital costs + fixed O&M)/ annual expected generation hours) + variable O&M + fuel. EIA assumes that the lead time on advanced nuclear is 6 years, making projects that began in 2025 operational by 2031. EIA also assumes the overnight capital costs of advanced nuclear are $9,831/kW. Overnight capital costs are the costs of a project if it accrued zero interest. *https://www.eia.gov/outlooks/aeo/assumptions/pdf/EMM_Assumptions.pdf*

[66] *https://www.nlr.gov/solar/market-research-analysis/solar-installed-system-cost*

[67] For instance, the bill contemplates that "development" costs will be passed through to rate payers. Unlike decommission costs (also passed through), development costs are normally incurred up front. The language does not explain how these early costs would be recovered during the retail participation period.

[68] E. Howland, "AEP, other Ohio utilities could own nuclear power plants under state bill," Utility Dive, May 22, 2026, *https://www.utilitydive.com/news/aep-ohio-nuclear-power-smr-bill-oma/820841/*.

exports power within the territory. In 2024, Ohio imported approximately 13% of its 163,307 GWh electricity load.[69] That ability to import and export power across state borders is a central feature of deregulation.

While it is uncertain how important it is for Ohio's generation output to match its consumption, it is possible that Ohio may see an increase in electricity imports. The increase in data center demand in Ohio has caught the attention of both the General Assembly and Ohio's executive officers. Further, Ohio's leadership has also specifically identified an interest in Ohio being part of the supply chain for new nuclear power development. Ohio's Governor DeWine identified energy as an important pillar to Ohio's economy, noting that "Ohio must have an energy policy that ensures we have the supply we need for current and future demand, and will keep costs reasonable."[70] To that end, Ohio's economic development leader, JobsOhio, has funded an "Energy Opportunity Initiative" that includes, among other things, creating a "nuclear energy center of excellence" in Ohio that might help Ohio develop and attract SMR supply chain companies.[71]

But reintroducing vertically integrated regulation to Ohio's electricity rate base for the purpose of attracting new nuclear power is a very different proposition from supporting investment into energy technology manufacturing, research and training. Direct subsidies are one form of generation risk undermining the competitive electricity markets that have saved Ohio ratepayers many billions of dollars. This is especially so for generation that poses significant risk of cost overruns. Reintroducing the risk of undisciplined capital investment could undermine the policy goals set forth by the Governor – keeping power costs "reasonable."

Before adopting any legislation that reintroduces nuclear power into the rate base, the General Assembly should do a careful cost-benefit analysis, including an examination of the value of the externalities (such as carbon emission reduction) from such generation. It should also consider alternative strategies to accomplish those benefits. But it is important to fully understand the risk to ratepayers before those policies are put in place.

It is likewise important to remember that utilities are free to build and operate nuclear plants now – just not through regulated distribution companies. Such facilities would have to compete with other generation. If AEP or other utilities believe building new nuclear power plants will lead to the delivery of cost-effective generation to end-users, they may proceed to do so within the current regulatory structure. Ohio would very likely welcome such facilities.

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[69] U.S. EIA, Ohio Electricity Profile 2024, Table 10.

[70] *https://www.jobsohio.com/newsroom/news-press/gov-dewine-jobsohio-announce-100m-energy-opportunity-initiative?_sp=6284d7f3-9ec5-453d-ba23-26a8b74f2677.1784730116428*

[71] Id.



2 UTILITY ACCOUNTING AND NUCLEAR POWER

Utilities recoup their investments from ratepayers through accounting strategies that are managed by regulators. In Ohio, the regulatory agency that oversees recoupment is the Public Utility Commission of Ohio (PUCO). In this section, the Study Team sets forth how utility accounting was conducted before deregulation, how the practice changed after deregulation, and how it is likely to be conducted going forward, after the passing of House Bill 15. The Study Team then considers special problems with utility accounting that may apply specifically to nuclear energy.

2.1 UTILITY GENERATION ACCOUNTING BEFORE DEREGULATION

From the 1930s and until deregulation in 2001, generation markets in Ohio were operated by firms that were granted monopolies over local customer geographies. Electricity grids grew out of generation, and these systems met the definition of a "natural monopoly": high fixed costs to build and operate new systems, yet low marginal costs for additions to existing systems. Private ownership of distribution infrastructure made it difficult for any competing generation to supply customers, unless their generation was adjacent to the customer.

Policy makers determined that, if left to operate without oversight, natural monopolies would overcharge for and underproduce energy. Because electricity had become an essential part of consumers' day-to-day lives, policymakers sought to regulate this market in a manner to approximate the output and cost they would expect from a competitive market, were one to exist. In Ohio, as in other states, this was done through a regulatory commission that was tasked by state legislators to develop and deploy strategies to accomplish this.

Accounting for generation prior to deregulation was not separate from accounting for transmission and distribution.[72] All cost recovery from the system operations, from generation to delivery of electricity to the end user, was subject to approval by the Public Utility Commission of Ohio (PUCO). Under PUCO oversight, utilities account for operating costs (such as fuel, wages, and maintenance) and the capital costs of assets they have already invested in, minus accumulated depreciation. Regulators then determine an allowed rate of return on capital investment based on financial market data and the returns earned by similar-risk investments. Rates are set so utilities can recover their costs and earn this allowed rate of return on their investments through the sale of electricity to consumers.

This system of regulation is commonly referred to as "cost-of-service" or "rate-of-return" regulation.

[72] Ohio Revised Code, Section 4928.31 "Transition Plan." Available online: https://codes.ohio.gov/ohio-revised-code/section-4928.31

Under this framework, regulators determine the total amount of revenue a utility is allowed to recover through electricity rates based upon its operating costs, depreciation, and an allowed rate of return on invested capital.[73] In simplified form, the formula can be expressed as:

$$RR=O\&M+A\&G+T+D+(WACC\cdot RB)$$

Where RR is the revenue requirement, O&M is operation and maintenance expenses, A&G is administration and general expenses, T is taxes, D is depreciation, WACC is the weighted average cost of capital, and RB is the rate base that is equal to the gross value of assets minus accumulated depreciation plus working capital.[74]

The rate base under this model consists of the value of power plants, transmission lines, distribution lines, substations and other infrastructure that utilities have invested in and placed into service, minus accumulated depreciation. Regulators then determine an allowed rate of return designed to approximate the cost of attracting capital from investors. This system was designed to replicate the outcomes of a competitive market while preserving the efficiencies associated with a single integrated utility provider. States granted utilities monopoly service territories and, in exchange, the utilities accepted an obligation to provide reliable service at rates approved by the state.

In Ohio, the PUCO is tasked with reviewing rate cases, approving major infrastructure projects, and determining whether investments have been prudently incurred before allowing utilities to recover their costs from consumers. Although PUCO and similar commissions are formally independent regulatory bodies, they face significant informational disadvantages to the companies they regulate. Utilities possess greater access to engineering studies, fuel forecasts, construction estimates, and demand projections than the regulators overseeing them. As a result, commissions have often relied heavily upon utility-provided forecasts and expert testimony when determining whether new generation projects are necessary.

2.2 UTILITY ACCOUNTING AFTER DEREGULATION OF GENERATION

Under the deregulated framework adopted in Ohio and many other states, vertically integrated utilities were required to separate their competitive generation functions from their regulated transmission and distribution operations. Generation assets were either transferred into legally distinct affiliates or sold to independent generation companies entirely[75]. The objective of this restructuring was to prevent utilities from using their transmission and distribution infrastructure monopolies to disadvantage competing power producers. Transmission and distribution systems remained regulated natural monopolies because duplicating poles, wires, substations, and local delivery infrastructure continued to be economically inefficient. By contrast, policymakers concluded that electricity generation itself could potentially function as a competitive market in which many firms could build and operate power plants that sold electricity into wholesale markets for ultimate distribution through the regulated grid.

This restructuring of the energy market fundamentally changed how generation costs were accounted for and recovered. Under traditional regulations, utilities recovered generation-related operating costs, fuel expenses, depreciation, and returns on generation investments directly through regulated retail electricity rates. After deregulation, generation costs were largely removed from the regulated rate base and instead became subject to competitive wholesale market pricing.

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[73] Federal Energy Regulatory Commission, "Cost-of-Service Rates Manual," pg. 6. Available online: *https://www.ferc.gov/sites/default/files/2020-08/cost-of-service-manual.pdf*

[74] See Lesser, supra, at 51.

[75] Ohio Revised Code, Section 4928.31 "Transition Plan." Available online: https://codes.ohio.gov/ohio-revised-code/section-4928.31

Under the deregulated model, independent generators would now earn revenues by selling electricity into organized wholesale energy markets operated by regional transmission organizations such as PJM Interconnection.[76] Generators, utilities, and other market participants could also use bilateral contracts and trading platforms such as the Intercontinental Exchange to manage electricity price risk through forward, futures, options, and other energy-related contracts. Generators submit offers reflecting the price at which they are willing to supply electricity, and market operators like PJM dispatch the lowest-cost combination of resources necessary to meet demand. Rather than regulators guaranteeing recovery of generation investments, generation owners increasingly bear the financial risks associated with construction costs, fuel prices, and market conditions.

However, policymakers also recognized that electricity markets face reliability challenges that ordinary commodity markets did not. Electricity cannot easily be stored on a large scale, and supply and demand must remain balanced continuously in real time to maintain grid stability. Because of these reliability concerns, deregulated markets retained mechanisms to ensure that sufficient generation capacity would remain available even during periods of peak demand or unexpected outages.

This led to the development of "capacity markets" which compensate generators not only for the electricity they produce but also for maintaining available generating capability that can be called upon when needed.[77] Capacity markets were not fully separated from regulation in the same manner as energy generation because policymakers feared that energy-only markets might not provide sufficient financial incentives for firms to maintain adequate reserve margins.

Electricity prices are often capped during scarcity events to prevent extreme price spikes, which can limit the revenues generators earn during periods when additional capacity is most valuable.[78] Without supplemental compensation, firms might underinvest in generation resources needed for long-term reliability. Capacity markets therefore function as a parallel mechanism through which grid operators procure commitments from generators to remain available in future years. In regions such as PJM, generators participate in forward capacity auctions where they receive payments in exchange for agreeing to supply electricity or reduce demand during future reliability emergencies.

As a result, capacity became a distinct accounting and market concept after deregulation.[79] Under the traditional vertically integrated model, reserve capacity requirements were managed internally by utilities as part of their obligation to serve customers reliably. The costs of maintaining excess generating capability were incorporated into the utility's overall regulated revenue requirement and recovered through retail rates. After deregulation, capacity obligations became formalized through market rules administered by regional transmission organizations. Load-serving entities, including retail electricity suppliers and utilities, are required to procure sufficient capacity to meet projected customer demand plus reserve margins established by reliability regulators. Generators that clear capacity auctions receive a separate stream of revenue in addition to revenues earned from selling electricity into energy markets.

Even after deregulation, distribution utilities remain regulated. Regulators continue to review utility investments in poles, wires, substations, and related infrastructure, and they still establish rates

[76] Federal Energy Regulatory Commission, "PJM Interconnection Quick Guide," October 16, 2025. Available online: *https://www.ferc.gov/media/pjm-interconnection-quick-guide*

[77] Cramton, Peter, Axel Ockenfels, and Steven Stoft. "Capacity market fundamentals." Economics of Energy & Environmental Policy 2, no. 2 (2013): 27-46.

[78] Sirin, Selahattin Murat, and Ibrahim Erten. "Price spikes, temporary price caps, and welfare effects of regulatory interventions on wholesale electricity markets." Energy Policy 163 (2022): 112816.

[79] Bhavaraju, Murty P., Benjamin Hobbs, and Ming-Che Hu. "PJM reliability pricing model-A summary and dynamic analysis." In 2007 IEEE Power Engineering Society General Meeting, pp. 1-3. IEEE, 2007.

that allow utilities to recover prudent costs and earn an approved return on those investments. Transmission investments are similarly regulated, although they are overseen at the federal level through the Federal Energy Regulatory Commission. Meanwhile, generation prices are more closely tied to market outcomes, with wholesale electricity markets determining which power plants operate at any given time based upon bids, fuel costs, and system demand conditions. The resulting system is therefore neither fully deregulated nor fully regulated. Instead, it represents a hybrid structure that attempts to combine competitive pressures in electricity generation with continued regulatory oversight of the monopoly infrastructure necessary to deliver reliable, safe, and cost-effective electric service.

2.3 UTILITY EFFORTS TO TRANSFER GENERATION COSTS INTO DISTRIBUTION RATE BASE

After Senate Bill 3 was passed in 1999, utilities were required to keep accounting for generation and distribution separated.[80] This was the legislature's goal with deregulation: isolate generation from distribution so distribution could still operate as a regulated monopoly while generation enterprises could compete against one another.

Under Ohio SB 3, electric distribution utilities were not required to sell their generation assets, they were only required to account for generation assets separately from assets used for distribution. Distribution could still be commonly owned by the same companies that owned generation. Affiliate relationships between companies that owned distribution and generation were still permitted. The separation that was designed to make deregulation work was built on accounting separation, corporate separation, rules around affiliates, and overview by the PUCO. The PUCO was charged with ensuring that distribution utilities did not give preference or advantage to affiliated companies.[81] Ohio's administrative rules required separation plans to have structural safeguards, separate accounting, affiliate lists, financial arrangement disclosures, codes of conduct, cost allocation manuals, compliance monitoring, and compliance procedures.[82]

This approach – allowing distribution and generation operations to be affiliated within the same company – meant that the companies would be required to set up an "accounting wall" between them. Affiliated distribution and generation companies could share "assets, services, and products."[83] These each needed to be assigned to either the distribution or generation side of the ledger for any of these closely affiliated distribution and generation companies.

Since distribution was still endowed with a guaranteed rate of return for costs invested, this created an incentive for companies to account for as many of these costs as possible as distribution costs. Such a strategy gave distribution utility generation a significant advantage against competitors in the generation market. It was then up to the PUCO to analyze the allocations made by utilities and judge whether they were placed into the proper categories. This process requires transparency of accounting and intimate knowledge of internal corporate business models to be carried out with any level of certainty. Commissioners were always at an information disadvantage to utilities when policing cross subsidies between affiliated distribution and generation ventures.

A common strategy for utilities to transfer generation into distribution costs accounting is through shared-service cost allocation. While Ohio's corporate separation scheme required separate books, records, and accounts between generation and utility projects, shared corporate structures still lead to judgment calls in accounting. Operations like executive time,

[80] Direct Energy. "The history of electricity deregulation in Ohio." November 28, 2023. *https://www.directenergy.com/en/learn/energychoice/ohio-history-electric-deregulation* Accessed June 12, 2026.

[81] Ohio Revised Code Section 4928.17. Corporate separation plans.

[82] Ohio Administrative Code. Rule 4901:1-37-05. Application.

[83] Ohio Admin. Code 4901:1-37-08(A), (D)–(G); Ohio Rev. Code Ann. § 4928.17(A)(3).

legal costs, regulatory costs, lobbying, information technology, billing, customer service, finance, and service-company charges must be allocated to either generation or distribution when a utility owns both. Separating accounting does not eliminate utility discretion, and utilities have incentive to account for generation as distribution expenses. Regulators generally know how to watch for misclassification of utility cost accounting,[84] but they still depend on utilities to follow an honor system. A good example of cross subsidies occurred in 2016, when the Ohio Public Utilities Commission authorized FirstEnergy to assess a "Distribution Modernization Rider" to its ratepayers to pay for "grid modernization" that might be more than what would normally be allowable in a utility rate case.[85] FirstEnergy argued that adding this rider would improve the company's credit position and access to capital. This would allow FirstEnergy to make grid modernization investments that could theoretically lead to customer benefits like fewer and shorter outages, faster reconnection, better voltage management, reduced line losses, better integration of distributed energy resources, better customer usage data, or lower long-run operating costs.

Consumer advocates disagreed with the charge, though, arguing that no distribution modernization projects were required to be implemented in exchange for the extra revenue collected with the rider. In 2019, the Ohio Supreme Court sided with the consumers, finding that the up-front nature of the funds improperly allowed FirstEnergy to collect fees without improving the grid.

Instead, FirstEnergy had used these dollars to subsidize an unregulated generation affiliate.[86] Based upon this Supreme Court decision, the PUCO later ordered FirstEnergy to pay back $250.7 million in penalties and refunds. Yet according to at least one audit, FirstEnergy utilities collected $457.7 million over 2.5 years from ratepayers under the riders.[87] It is unclear if or when the PUCO will order the rest of the money be returned to the ratepayers.

After the House Bill 6 scandal, there was a movement in the Ohio General Assembly to reform electricity regulation to end both direct and cross subsidies of generation in Ohio. This culminated in the passage of HB 15 in 2025; a bill designed in part to close loopholes that led to cross subsidization like that deployed in FirstEnergy's distribution modernization rider.[88]

House Bill 15 separated distribution and generation by explicitly banning distribution utilities from owning generation facilities. The bill did not ban parent companies from owning generation facilities in Ohio –- those companies are free to own and operate nuclear or other generation facilities in Ohio. Such facilities just must recoup their costs from customer contracts or through standard service auctions.

2.4 SPECIAL PROBLEMS IN NUCLEAR ACCOUNTING

The accounting process for nuclear energy is not fundamentally different than for other methods of electricity generation, but the economics of nuclear energy present unique challenges to regulators overseeing the separation of nuclear generation and utility-scale distribution.

2.4.1 DEVELOPMENT AND CONSTRUCTION COSTS

Nuclear power generation creates unique accounting challenges because utilities incur substantial costs long before a plant begins producing electricity or generating revenue. These costs include both development and construction phases. Development costs include site acquisition, engineering and design

[84] For example, this is a topic of discussion for FERC formula rate workshops. See, e.g. *https://www.ferc.gov/media/formula-rate-workshop-presentation*

[85] In re Application of Ohio Edison Co., 157 Ohio St.3d 73, 2019-Ohio-2401.

[86] Reuters, "Ohio regulators order FirstEnergy to pay more than $250 million in penalties and refunds." November 19, 2025. *https://www.reuters.com/legal/government/ohio-regulators-order-firstenergy-pay-more-than-250-million-penalties-refunds-2025-11-19/*

[87] Ohio Public Utilities Commission. "New audit of FirstEnergy Ohio utilities' DMR now available: A new audit report is now available." January 14, 2022. *https://puco.ohio.gov/news/dmr2022 Accessed May 15, 2026*. See also: Ohio Environmental Council. "OEC Statement on PUCO $250 million penalty against First Energy,

[88] Ohio General Assembly. "House Bill 15." *https://www.legislature.ohio.gov/legislation/136/hb15* Accessed May 15, 2026

work, environmental studies, licensing proceedings, and extensive regulatory compliance requirements. Unlike conventional generating facilities, nuclear plants often require years of planning and approval before construction begins, creating uncertainty regarding whether these early expenditures should be treated as current expenses or capitalized as long-term assets.

One of the primary accounting issues following the development phase involves the capitalization of financing costs during construction. Because nuclear facilities frequently require a decade or more to complete, utilities commonly use the allowance for funds used during construction to capitalize interest and other financing expenses rather than recognizing them immediately.[89] This allows utilities to defer cost recovery until the plant becomes operational, but it also substantially increases the recorded value of the facility before any electricity is produced. As construction periods lengthen, accumulated financing costs may become a significant portion of the total project cost.

Development costs also create important regulatory questions regarding prudence and risk allocation. Nuclear projects often involve uncertainty concerning licensing approvals, changing safety standards, future electricity demand, and the possibility that a project may be delayed or ultimately abandoned. Regulators therefore must determine whether development expenditures were prudently incurred and whether those costs should be recoverable from ratepayers. State utility commissions have responded by permitting capitalization of certain development costs while also subjecting nuclear investments to detailed prudence reviews intended to balance utility cost recovery with protection of consumers from excessive or speculative expenditures.

2.4.2 DELAYS AND COSTS OVERRUNS

Nuclear projects are particularly susceptible to cost overruns due to their long construction timelines, complex regulatory requirements, and high safety standards. These overruns raise important accounting questions regarding prudence. Regulators must determine whether rising costs reflect unavoidable external pressures or whether they stem from imprudent financial management, poor planning, or inefficient execution by the utility. Because nuclear facilities often take a decade or more to complete, even relatively small delays can significantly increase financing, labor, and material costs through the accumulation of interest and inflationary pressures.

Construction delays may also arise from changes in safety regulations, supply chain disruptions, shortages of specialized labor, or design modifications made during the building process. Determining responsibility for these delays is often difficult, particularly when projects involve multiple contractors, shifting regulatory requirements, and evolving technology. As a result, prudence reviews frequently become contentious proceedings between utilities, regulators, consumer advocates, and investors.

If regulators determine that certain overruns resulted from mismanagement or inefficient project execution, those costs may be excluded from the rate base, directly impacting the utility's ability to earn a return on investment. Such disallowances can impose

FIGURE 14
WILLIAM H. ZIMMER POWER STATION



Photo: Antony-22 (2017) [90]

[89] Federal Energy Regulatory Commission, "Allowance for Funds Used During Construction." Available online: *https://ferc.gov/enforcement-legal/enforcement/accounting-matters/allowance-funds-used-during-construction*

[90] H. Zimmer Power Station aerial 2017a [Photograph]. Wikimedia Commons. *https://commons.wikimedia.org/wiki/File:William_H._Zimmer_Power_Station_aerial_2017a.jpg*

TABLE 3
COST OVERRUNS FOR OHIO NUCLEAR POWER PLANTS, $2026

Project	Projected Cost	Final Cost	Cost Overrun
Davis-Besse Unit No. 1	$557 million	$2.7 billion	4.8x
William H. Zimmer Power Station	$2.2 billion	$5.4 billion (abandoned)	2.5x
Perry Nuclear Plant	$5.3 billion	$16.9 billion	3.2x

Source: National Regulatory Research Institute,[91] Time Magazine,[92] and New York Times.[93]

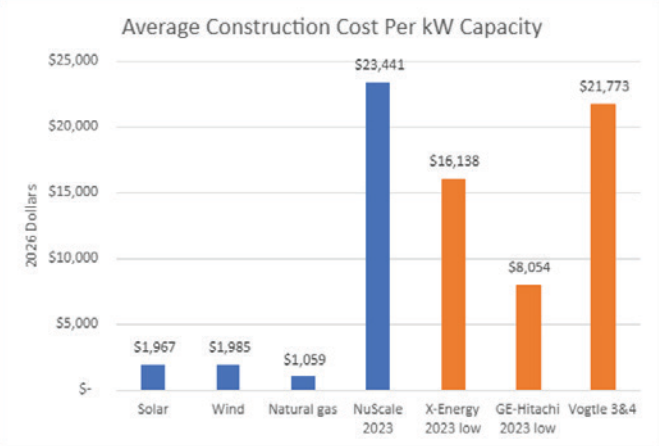
major financial losses on utilities and may discourage future investment in large-scale generation projects. Conversely, if cost overruns are deemed reasonable and included in the rate base, consumers may face substantial increases in electricity rates to recover expenses that greatly exceed original projections. This creates a central regulatory challenge: balancing the need to protect ratepayers from excessive costs while still allowing utilities a reasonable opportunity to recover investments in critical infrastructure.

Each of Ohio's three major nuclear projects had cost overruns more than two times their initial projections, including the William H. Zimmer Power Station which was never built. See Table 3.

Proponents of small modular reactors suggest that this new method of building nuclear reactors will be less subject to cost overruns compared to larger traditional reactors. While there may be reasons to believe these claims, the evidence provided by the limited number of existing small modular reactor projects to date suggests that the issue of cost overruns still exists.

The Institute for Energy Economics and Financial Analysis (IEEFA) released a report in 2024 looking at cost overruns in the existing small modular reactor projects around the world.[94] They found that construction costs exceeded estimates by 300% and 400% for the two operational small modular reactors in China and Russia respectively. A small modular

FIGURE 15
AVERAGE COST OF CONSTRUCTION PER KW OF DIFFERENT GENERATION SOURCES IN 2026 DOLLARS



The average cost of construction per kW of different generation sources in 2026 dollars (orange shows projected costs and blue shows actual costs). The lowest cost nuclear project is over four times as expensive as any other form of electricity generation in construction costs. Source: EIA for wind, solar and natural gas construction costs, and IEEFA for nuclear construction costs.[95]

[91] "CONSTRUCTION COST OVERRUNS IN ELECTRIC UTILITIES: SOME TRENDS AND IMPLICATIONS". *https://www.canr.msu.edu/ipu/uploads/migration/2016/12/NRRI-Construction-Cost-Overruns-Electric-80-8-Nov-80-1.pdf* p. 22. Accessed June 12, 2026

[92] Grieves, Robert T. "A $1.6 Billion Nuclear Fiasco." Time Magazine. October 31, 1983. *https://time.com/archive/6855243/a-1-6-billion-nuclear-fiasco/* Accessed June 12, 2026.

[93] New York Times. " OHIO UTILITIES FACE NUCLEAR PLANT DOUBTS." April 30, 1984. *https://www.nytimes.com/1984/04/30/business/c-ohio-utilities-face-nuclear-plant-doubts-162108.html* Accessed June 12, 2026 [93] Antony-22. (2017, October 18). William

[94] Schlissel and Wamsted, IEEFA, supra.

[95] Solar, wind, and natural gas costs from EIA https://www.eia.gov/electricity/generatorcosts/. Nuclear costs from IEEFA *https://ieefa.org/sites/default/files/2024-05/SMRs%20Still%20Too%20Expensive%20Too%20Slow%20Too%20Risky_May%202024.pdf*

reactor that is under construction in Argentina is expected to have a cost overrun of 700%.

These cost overruns make nuclear energy less economically viable when compared to other forms of electricity generation. Comparing data from the IEEFA report to data from the Energy Information Administration, the capacity-weighted average construction cost per kW of nuclear reactor projects is over four times as high as any other form of electricity generation.[96]

2.4.3 ALLOCATION OF BALANCE OF PLANT COSTS AND INTERCONNECTIONS

In addition to the reactor itself, nuclear generating facilities require extensive supporting infrastructure commonly referred to as "balance of plant" costs. These costs include all parts of the power plant that do not include the primary electricity generating device.[97] Although these components are not directly involved in the nuclear reaction process, they represent a substantial share of total project costs and create accounting and regulatory challenges regarding cost allocation and recovery.

One accounting issue involves determining how balance of plant assets should be categorized and depreciated. Certain components, such as transmission interconnections or general site infrastructure, may serve multiple generating units or provide systemwide benefits beyond a single nuclear facility. Utilities must decide how to allocate these costs among different assets, operating divisions, and customer classes. Regulators may also require distinctions between costs directly attributable to electricity generation and those associated with broader transmission or grid reliability functions. These allocation decisions can affect the utility's rate base, depreciation schedules, and the distribution of costs among ratepayers.

Interconnection costs create additional complications because nuclear plants are often located far from population centers and require transmission upgrades to connect to the electrical grid. These transmission investments may involve coordination between utilities, regional transmission organizations, and independent system operators, making it difficult to determine which parties should bear the associated costs. In some cases, transmission infrastructure primarily benefits the nuclear facility itself, while in others it may improve reliability or capacity across the broader grid. Regulators must determine whether interconnection costs should be fully assigned to the nuclear project, shared across multiple utilities, or recovered through regional transmission charges.

Balance of plant and interconnection expenditures also raise prudence concerns similar to those associated with construction overruns. Because these supporting systems are highly specialized and subject to evolving safety and reliability standards, costs may increase substantially during development and construction. Disputes may emerge about whether specific expenditures were necessary for safe plant operation or whether utilities pursued excessively costly designs. As with other aspects of nuclear accounting, regulators must balance the need to ensure reliable infrastructure and grid integration against the obligation to protect consumers from unreasonable or inefficient spending.

2.4.4 DEPRECIATION

One of the key inputs into the regulatory accounting model is the depreciation of existing assets. Nuclear generating facilities create unusual depreciation challenges because they are capital-intensive, have very long operational lifespans, and are subject to changing regulatory and technological conditions over time. Utilities must determine both the useful life of the facility and the method by which construction and equipment costs will be recovered through annual depreciation charges. Because nuclear plants are often designed to operate for 40-60

[96] Energy Information Administration," Construction cost data for electric generators installed in 2023," July 28, 2025. Available online: *https://www.eia.gov/electricity/generatorcosts/*

[97] Construction Front," BoP Contracts: What are they and how do they work?" Available online: https://constructionfront.com/balance-of-plant-bop-contract/

years or more, even relatively small adjustments to depreciation schedules can significantly affect annual electricity rates, utility earnings, and the total amount ultimately recovered from ratepayers.

While all utilities need to account for the depreciation of their assets, nuclear reactors are unique compared to other forms of electricity generation because their useful lifespan is significantly longer. According to the Energy Information Administration, the average gas-fired power plants operate for 48 years.[98] This is a common lifespan for a fossil fuel burning plant, and many renewable options have even shorter operating lives.[99] A nuclear reactor, on the other hand, might be operable for 80 years. That may change how utilities and regulators address depreciation.

Nuclear depreciation policy also creates broader questions around risk allocation between investors and consumers. Longer depreciation schedules generally lower near-term electricity rates but expose ratepayers to the risk that a plant may become uneconomic or retire before costs are fully recovered. Shorter depreciation schedules increase current rates but reduce the likelihood that utilities will be left with stranded assets. This means that regulators and utilities need to deal with competing goals of rate stability, investor certainty, and consumer protection. This in turn heightens the importance of determining how or when nuclear power generation is placed into the distribution rate base.

2.4.5 INSURANCE

Nuclear generation also creates unique accounting challenges related to insurance and liability exposure. Unlike most other forms of electricity generation, nuclear accidents have the potential to produce catastrophic damages that exceed the financial capacity of individual utilities or private insurers.[100] As a result, nuclear energy insurance operates under a specialized regulatory framework centered on the Price–Anderson Act, which combines private insurance markets, industrywide risk pooling, and federally-mandated liability protections for the utilities.

The Price-Anderson Act establishes a two-tier liability system to compensate the public in the event of a nuclear accident. First, each commercial nuclear power plant must carry the maximum amount of private liability insurance available, currently $500 million. Second, if damages exceed that amount, there is an industry-wide pool of about $16 billion that may be accessed. Should these funds be exhausted, the nuclear industry's liability is capped.[101] Of course, $16 billion would not be enough to cover the damage created by a core meltdown. The Fukushima nuclear disaster damage has been estimated to be about $500 billion.[102]

If damages exceed the Price-Anderson liability cap, there is no source of additional compensation. As a result, any damage beyond the statutory liability limit would be up to the citizens, ratepayers and/or states to cover, unless there is future congressional action.

One major accounting issue involves the treatment of insurance costs as operating expenses recoverable through electricity rates. Nuclear operators are generally required to maintain substantial levels of liability coverage through organizations such as American Nuclear Insurers and Nuclear Electric Insurance Limited, which spread the financial risk of major accidents across multiple reactor operators. These insurance obligations can fluctuate over

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[98] Energy Information Agency, "Most generator retirements over the past decade were older natural-gas fired units." Available online: *https://www.eia.gov/todayinenergy/detail.php?id=4290*

[99] Climate Council, "What happens to renewables when they reach retirement age?" Available online: *https://www.climatecouncil.org.au/resources/what-happens-to-renewables-when-they-reach-retirement-age/*

[100] Gudgel, John E. "Insurance and the public–private management of risk at US commercial nuclear power plants." Risk Management and Insurance Review 26, no. 4 (2023): 437-465.

[101] Holt. Price-Anderson Act: Nuclear Power Industry Liability Limits and Compensation to the Public After Radioactive Releases. 2025.

[102] See, e.g. "Full Report: Fukushima Daiichi," the American Nuclear Society Special Committee on Fukushima (June 2012). *https://www.ans.org/pubs/reports/fukushima/report/*

time depending on regulatory requirements, plant age, operational history, and broader conditions in insurance markets. Regulators must therefore determine whether rising insurance costs are prudently incurred and whether they should be passed directly to ratepayers or absorbed by shareholders. Because insurance expenses may increase significantly following major nuclear incidents anywhere in the world, utilities may face sudden changes in operating costs unrelated to the performance of their own facilities.

Insurance accounting also raises questions about the treatment of low-probability but high-cost risks. Traditional utility ratemaking is designed around predictable operational expenses and capital recovery, but catastrophic nuclear liability involves uncertain future contingencies that may never occur during the life of the plant. Utilities and regulators must decide how to account for contingent obligations that are difficult to quantify using ordinary accounting methods, including potential retrospective assessments imposed after a major accident. At the same time, insurers and regulators use inspections, premium structures, and safety performance evaluations to encourage risk reduction and operational discipline within the industry. Nuclear insurance requirements thus reflect not only technical accounting practices but broader policy judgments regarding public risk, financial responsibility, and the social costs of nuclear generation.

2.4.6 DECOMMISSIONING COSTS

Nuclear power plants create significant accounting challenges at the end of their operational lives. Unlike most conventional generating facilities, nuclear plants require extensive decommissioning procedures involving dismantling radioactive systems, managing contaminated materials, storing or disposing of spent fuel and radioactive waste, and restoring plant sites to acceptable environmental conditions. These activities may continue for decades after electricity production has ceased and can require billions of dollars in future expenditures.[103] Utilities must determine how to estimate, fund, and account for these future obligations long before decommissioning occurs while also selecting among alternative decommissioning strategies such as immediate dismantling, deferred dismantling, or long-term safe enclosure.

One of the primary accounting issues associated with decommissioning involves estimating future liabilities under conditions of uncertainty. The ultimate cost of decommissioning depends on factors such as future labor expenses, waste disposal costs, inflation, regulatory standards, technological developments, environmental remediation requirements, and the availability of long-term storage facilities for radioactive materials. Because these costs may not be incurred until many decades after a plant begins operation, even small changes in assumptions like discount rates or inflation can dramatically affect present-value liability estimates. Utilities commonly establish decommissioning trust funds during the operating life of the plant, collecting revenues from ratepayers over time to build a large enough bankroll to meet future obligations. This means that regulators need to evaluate whether contribution levels are adequate and whether investment strategies for decommissioning funds appropriately manage all the risks involved.

Decommissioning accounting also raises important questions around intergenerational equity, stranded costs, and long-term public safety. If utilities underfund decommissioning obligations during the productive life of the plant, future ratepayers or taxpayers may ultimately bear costs associated with facilities from which they received little or no benefit. Conversely, excessive collections may require current consumers to overpay for uncertain future liabilities. Additional complications arise when plants retire earlier than expected due to economic conditions, safety concerns, environmental requirements, or changes in energy markets, potentially leaving

[103]Park, Kwangheon, Seunghyun Son, Jinhyuk Oh, and Sunkuk Kim. “Sustainable decommissioning strategies for nuclear power plants: A systematic literature review.” Sustainability 14, no. 10 (2022): 5947.

TABLE 4
PROJECTED DECOMMISSIONING COSTS FOR SELECT NUCLEAR SITES NEAR OHIO

Site	State	Cost
Davis-Besse	Ohio	$490 million
Perry	Ohio	$680 million
Beaver Valley	Pennsylvania	$1.3 billion
Fermi 2	Michigan	$1.1 billion
Donald C. Cook	Michigan	$980 million
Palisades	Michigan	$560 million

Projected decommissioning costs for select nuclear sites. Source: Nuclear Regulatory Commission.[104]

insufficient time to fully fund decommissioning reserves. Regulators therefore must balance the need to ensure adequate long-term funding for safe plant retirement and waste management against the obligation to protect current consumers from excessive or speculative charges while maintaining environmentally responsible decommissioning practices.

Table 4 shows the projected cost of decommissioning select plants in Ohio and neighboring states. These numbers are reported by the Nuclear Decommissioning Collaborative deriving costs from the Nuclear Regulatory Commission's 2017 Decommissioning Funding Status Report and are presented in 2018 dollars.

As of 2026, there have been four U.S. nuclear facilities that have completed the process of decommissioning and are no longer under license with the Nuclear Regulatory Commission. Another 27 are in the process of decommissioning.[105] One decommissioned plant was comparable in size to Davis Besse: the 560 MW Connecticut Yankee Atomic Power Company plant in Haddam Neck, Connecticut was shut down in 1996. Its decommissioning was completed in 2007 at a cost of $1.2 billion (2018 dollars).[106] This suggests that if decommissioning funds are set at $490 and $680 million for Davis Besse and Perry, respectively, these may be too low. On the other hand, the Entergy Vermont Yankee 620 MW nuclear power plant, now being decommissioned by Northstar Group Services, is expected to be finished in 2026 for a total decommissioning cost of around $536 million – less than the $760 estimated in 2018.[107]

FIGURE 16
VERMONT YANKEE NUCLEAR POWER PLANT



Vermont Yankee Nuclear Power Plant will be decommissioned by 2026 (Photo: Nuclear Regulatory Commission).[108]

[104]The Nuclear Decommissioning Collaborative. https://decommissioningcollaborative.org/ Accessed June 12, 2026.

[105]Nuclear Regulatory Commission, "Backgrounder on Decommissioning Nuclear Power Plants." Available online: *https://www.nrc.gov/reading-rm/doc-collections/fact-sheets/decommissioning*

[106]https://decommissioningcollaborative.org/connecticut-yankee/

[107]S. Smallheer, "Vermont Yankee decommissioning on budget, on time," Brattleboro Reformer, Sept 19, 2023. *https://www.reformer.com/local-news/vermont-yankee-decommissioning-on-budget-on-time/article_4d3c99e4-5715-11ee-8156-870c1645f869.html.* See also: *https://decommissioningcollaborative.org/vermont-yankee/*

[108]U.S. Nuclear Regulatory Commission. (2015, May 20). Vermont Yankee Unit 1 [Photograph]. Flickr. *https://www.flickr.com/photos/nrcgov/17856558482/*



3 PROPOSALS TO SOCIALIZE NUCLEAR GENERATION COSTS INTO THE DISTRIBUTION RATE BASE

Since electricity generation was fully deregulated in 2001, and more fully in 2011, there have been multiple efforts by distribution utilities to return Ohio to vertically integrated electricity regulation. The most notable foray into reregulation was in 2019 with the passage of House Bill 6, which provided ratepayer subsidies for nuclear and coal-fired power. HB 6 was not fully repealed until HB 15 was passed in 2025. Since adoption of House Bill 15, members of the Ohio General Assembly have proposed new legislation to reintroduce distribution company ownership of nuclear power generation in Ohio.

3.1 RECENT PROPOSED OHIO LEGISLATION

Representatives Adam Mathews and Bob Peterson recently introduced House Bill 862, a bill designed to alter the separation between electric distribution utilities and electric generation ownership in Ohio. The bill authorizes electric distribution utilities to construct, own, and operate nuclear generating facilities if they obtain a nuclear project financing order from the Public Utilities Commission of Ohio.[109]

3.1.1 IMPACTS ON THE RATE BASE

One of the most significant accounting and regulatory provisions in House Bill 862 concerns the treatment of nuclear assets within the utility rate base. On this topic, the legislation would enable nuclear generation costs to be placed into the utility distribution rate base:[110]

(A) The electric distribution utility establishes a separate accounting ledger to record all costs and revenues associated with owning and operating the nuclear generating facility, including the accrual for construction work in progress during the period following technical completion and continuing until the facility commences commercial operation.

(B) For purposes of establishing the utility's base rates under Chapter 4909. of the Revised Code, the nuclear generating facility shall be reflected in the utility's rate base for the life of the nuclear generating facility, and this ratemaking treatment shall be afforded during the retail participation agreement term. Subject to divisions (C) and (D) of this section, all prudently incurred costs related to the nuclear generating facility shall be reflected in the utility's distribution rates established under Chapter 4909 of the Revised Code for the life of the facility and including during the retail participation agreement term.

The proposed bill also enables utilities to establish a separate accounting ledger for all costs and revenues associated with the nuclear facility, including for construction work in progress during the period between "technical completion and commercial operation." This provision is especially important for nuclear projects because lengthy testing and licensing periods can delay commercial operation for years after construction is complete. Allowing these costs to remain capitalized reduces short-term earnings pressure on the utility and supports continued cost recovery.

[109]The Ohio Legislature, "House Bill 862," accessed May 27, 2026. Available online: *https://legislature.ohio.gov/legislation/136/hb862*. The wording of this legislation may change several times, and some parts may materially change. All quotes from the proposed legislation are from a May 2026 version as of writing.

[110]The Ohio Legislature, "House Bill 862," pg. 32, accessed May 27, 2026. Available online: *https://legislature.ohio.gov/legislation/136/hb862*

Unlike deregulated generation investments that rely on market revenues, new nuclear generation under the proposed legislation would provide utilities with a recovery mechanism from distribution customers socialized throughout the distribution territory. This is to shift investment risk from utility investors to the distribution system ratepayers – regardless of whether those ratepayers use any of the nuclear power.

3.1.2 RETAIL PARTICIPATION CARVE OUT

House Bill 862 proposes to mitigate this problem in part by limiting utility cost recovery during the first 20 years of nuclear facility operations. During this term, utilities would recover their costs from one or more "retail participation agreements," which will presumably operate like a retail power purchase or electricity supply agreement. Power purchase and electric supply agreements are commonly used instruments for commercial retail electric supply (CRES) companies to sell electricity to end users in Ohio. Their common feature is that the CRES company agrees to supply, and the end user agrees to purchase, all end user required electricity (often referred to as "energy" to distinguish it from the delivered electricity by the distribution company).[111]

The bill sets forth that "no costs for a nuclear generating facility authorized by a nuclear project financing order shall be recovered from any electric distribution utility customer except for the customer or group of customers that entered into the retail participation agreement."[112] However, elsewhere in the proposed statute, electric distribution companies would be allowed recovery of "development" costs from ratepayers – costs typically incurred prior to construction. Moreover, there appears to be nothing that prevents utilities from deferring some cost recovery (e.g. stretch out depreciation), in a manner that would transfer costs from retail customers to ratepayers after conclusion of the participation agreements.

In short, utilities would be incentivized to defer and carry nuclear plant construction costs, thereby artificially constraining the costs of the power sold therefrom and thereby enabling them to readily capture retail markets on long term contracts. The deferred costs would carry a 9% or more return on investment – recreating one of the problems that had led to so many massive cost overruns for nuclear plants in the past.

Distribution utilities would also be incentivized to aggressively project future load requirements, leading to overbuilding of generation, thereby recreating another problem from past nuclear power development eras. Indeed, the electric distribution companies have already consistently projected more required load than needed.[113]

3.1.3 AFTER THE RETAIL PARTICIPATION AGREEMENT EXPIRES

Challenging regulatory and accounting issues may arise under the proposed legislation after retail participation agreements expire or terminate. At that point, it appears, based upon the most recent draft of the legislation, that the PUCO may have to conduct an audit to determine whether the cost of electricity generated by the nuclear facility is less than, equal to, or greater than the prevailing market price of electricity.

If the facility's electricity costs are below or equal to market prices, the plant remains in the utility's rate base and all remaining costs (including decommissioning expenses) may be recovered from all customers for the remainder of the facility's life. If costs exceed market prices, the plant remains in the base, but only the market price of electricity may be recovered from ratepayers. This appears to require that the PUCO make an ongoing, periodic judgments of the market value of the generation, effectively determining that the costs were imprudently incurred

[111]Often the electric supply or power purchase agreements have provisions that set forth upper and lower limits on the power purchased. If, for instance, the buyer increases or decreased load requirements by more than 25% there might be a penalty for doing so.

[112]The Ohio Legislature, "House Bill 862," pg. 33, accessed May 27, 2026. Available online: *https://legislature.ohio.gov/legislation/136/hb862*

[113]"Electricity Demand Growth and Data Centers: A Guide for the Perplexed," Bipartisan Policy Center, Koomey Analytics, February 2025. See page 9, which presents a graph sourced from *https://www.ferc.gov/industries-data/electric/general-information/electric-industry-forms/form-no-714-annual-electric/overview*

if the costs of electricity generated from the nuclear plants were above the current retail market value. Such an interpretation of the provision would render the legislation meaningless.

3.2 BENEFITS TO OHIO RATEPAYERS

Under this proposed legislation, Ohio's ratepayers could see benefits through two primary channels. First, there would be benefits related to increased local and dispatchable energy supply. Additional local generation can place downward pressure on electricity prices by increasing supply and reducing dependence on imported power. This might be more important for areas that suffer from grid constraints, such as in northeast Ohio, where electricity cannot be readily imported from the north. Further, new nuclear facilities could also improve grid reliability. Local nuclear plants can provide a stable source of electricity that complements intermittent renewable resources.

The second benefit nuclear power provides to ratepayers is that it produces no carbon dioxide emissions. It is hard to estimate the value of this benefit, but as climate change has intensified in recent years, it is likely that this benefit will increase in value over time. Indeed, the urgency to decarbonize is such that it may render the long lead time for nuclear plants problematic. To the extent that more dispatchable power is required, combined cycle natural gas plants, with carbon capture and sequestration, may be required to respond timely to the urgency presented by climate change.

Finally, nuclear facilities also typically operate for many decades, allowing customers to benefit from a long-lived source of electricity after the initial construction costs have been recovered. If a facility ultimately produces electricity at a cost below prevailing market prices, the legislation allows those benefits to be shared more broadly among ratepayers through continued rate-base treatment after the expiration of retail participation agreements.

3.3 COSTS TO OHIO RATEPAYERS

Nuclear reactors have a long history of significant cost overruns and schedule delays.[114] Construction delays increase labor expenses, financing costs, and material costs, while design modifications and regulatory changes can require substantial additional investment after construction has already begun. Recent construction has not significantly altered this narrative. Existing small modular reactors build in other countries have been subject to construction delays and cost overruns much like their larger predecessors.[115] Likewise, more traditional construction, such as the Vogtle generating station in Georgia, demonstrate the magnitude of the risk. Originally projected to cost approximately $14 billion, the project ultimately exceeded $25 billion.[116]

In a deregulated energy generation market, these risks are shouldered by investors and project owners. The possibility of cost overruns creates an incentive for developers to control expenses and accurately evaluate project feasibility before construction begins. Reregulation of nuclear power would alter this risk allocation by allowing nuclear facilities to become part of a regulated utility's rate base. Once an asset enters rate base, prudently incurred costs become eligible for recovery from customers, along with an authorized return on investment. While the Public Utility Commission may be able to shield ratepayers from some of these costs, past examples such as the Vogtle plant have shown that ratepayers usually bear cost overruns.[117]

Proposed HB 862 seeks to protect ratepayers during the term of retail participation agreements by limiting, in part, cost recovery to participating customers. However, it is unclear how well this protection would work. The bill appears to permit costs that

[114]Potter, Brian. "Why does nuclear power plant construction cost So much?" Institute for Progress (2023).

[115]Schlissel, and Wamsted, IEEFA, supra.

[116]Eash-Gates, Philip, Magdalena M. Klemun, Goksin Kavlak, James McNerney, Jacopo Buongiorno, and Jessika E. Trancik. "Sources of cost overrun in nuclear power plant construction call for a new approach to engineering design." Joule 4, no. 11 (2020): 2348-2373.

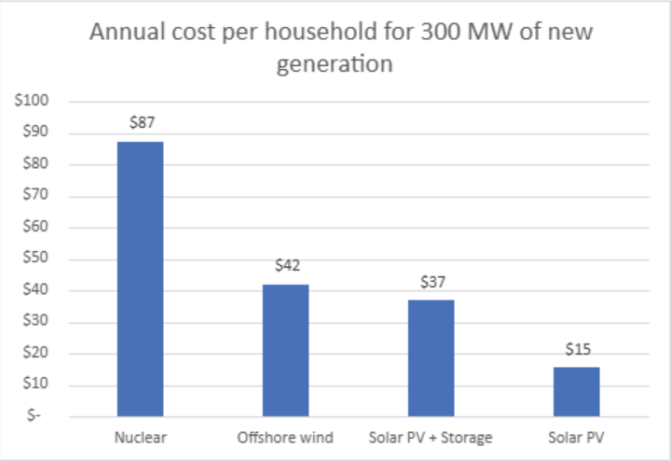
[117]Patty Durand," After 2 years, ratepayer pain and political fallout from Georgia's nuclear plant Vogtle," Utility dive. Available online; *https://www.utilitydive.com/news/after-2-years-ratepayer-pain-political-fallout-georgia-nuclear-vogtle/817792/*

are not recovered during the agreement period to be deferred for future regulatory recovery. Cost overruns are not eliminated when they cannot be recovered immediately; instead, they may accumulate as deferred balances that hit the ratepayers years later. Development costs, deferred balances, and decommissioning obligations, may be socialized across the rate base for the remainder of the facility's operating life. Customers who never participated in the original agreements may ultimately become responsible for costs generated by decades of construction delays, financing expenses, and project overruns.

The Study Team estimated how much more a 300 MW nuclear facility would cost a typical Ohio household than alternative sources of generation, assuming no cost overruns, and using IEEFA's levelized cost per kWh of generation.[118] This assumes the above market costs were socialized across the AEP Ohio ratepayer jurisdiction. According to the Energy Information Association, about 35% of the electricity in Ohio is consumed by residential users.[119]

Our model estimates electricity costs under different generation facility types built in the AEP Ohio jurisdiction, spread among the 1.3 million residential customers.[120] Assuming AEP Ohio households consume the same proportion of electricity as Ohio households generally, one 300 MW nuclear facility would cost households an additional $46 to $72 per year. Reregulation would, however, encourage the utility to build multiple 300 MW plants, since full recovery would essentially be guaranteed, with a 9-11% return on capital investments. Ten such plants would mean $460-720/year per household – with no cost overruns.

FIGURE 17
ANNUAL COST PER HOUSEHOLD FOR 30 MW OF NEW NUCLEAR GENERATION



Nuclear is over twice as expensive for households compared to renewable energy options. Source: IEEFA, EIA, and AEP Ohio.[121]

3.4 IMPACTS ON RETAIL MARKETS

The purpose of a deregulated market is to promote competition that leads to greater production efficiency and, in turn, lower costs for customers. This has worked well in Ohio, saved Ohio ratepayers some $37 billion since 2011, and an average of over $0.02/kWh for all users in Ohio – residential, industrial or commercial.[122] This successful competitive market will, however, be put at risk by significant subsidies to generation.

It has long been understood that subsidies to generation facilities result in market distortion. It discourages commercial retail electricity service companies from bidding on standard service auctions.[123] Research on the standard service auctions in Ohio found that fewer competitors in

[118]Schlissel and Wamsted, IEEFA, supra.

[119]Energy Information Association, "Ohio demand data." Available online: https://www.eia.gov/states/OH/data/dashboard/consumption

[120]Id.

[121]Schlissel and Wamsted, IEEFA, supra; EIA: Ohio Demand Data, Available online: *https://www.eia.gov/states/OH/data/dashboard/consumption, AEP Ohio, "AEP Ohio Fact Sheet" Available online: https://www.aepohio.com/lib/docs/company/about/AEP_Ohio_Fact_Sheet_2025.pdf*

[122]Thomas and Henning, Cleveland State University, supra.

[123]Ohio just recently stopped subsidizing uneconomic coal plants that cost ratepayers $500 million between 2019-2025. See: Kathiann M. Kowalski, "Ohio Finally Ends Subsidies for Two Scandal-Linked Coal Plants," Ohio Capital Journal, August 8, 2025.

these auctions lead to higher energy prices for consumers.[124]

Capacity markets have the exact same issue. Subsidized generation entry into a capacity market can suppress short term prices, but this can lead to a lack of investment in capacity generation, potentially causing long term resource inadequacies that dominate the short-term benefits.[125] To prevent a potential cycle of investment and disinvestment, the Federal Energy Regulatory Commission took action to keep generation subsidies from distorting capacity and wholesale generation markets.[126]

In 2018, FERC made a landmark decision when it ordered PJM to mitigate the capacity market impacts of subsidies by implementing a Minimum Offer Price Rule (MOPR). MOPR requires subsidized generation sources to submit bids at a price that reflects unsubsidized cost. In its ruling, FERC concluded that out-of-market payments could undermine the competitiveness of the market, leading to capacity generation investment shortfalls.

It would be better for ratepayers if the subsidies were not made at all. The artificial price increase means that the ratepayers first pay for the subsidy and pay for it again in the form of the higher bid into the capacity auction.[127] Other experts have argued that mitigating clean energy subsidies can have unintended consequences, primarily through the failure to reflect the cost of greenhouse gases in market prices.[128]

Ohio policy makers may reasonably conclude that the benefits of nuclear power are worthy of subsidies. However, it should first consider alternative strategies that do not distort the electricity generation markets that have worked so well to save ratepayers money, and to attract and retain industry. Well-designed subsidies target the outcome of technology, not the technology itself.

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[124]Dormady, Noah, Alfredo Roa-Henriquez, Matthew Hoyt, Matthew Pesavento, Grace Koenig, William Welch, and Zejun Li. "How are retail prices formed in restructured electricity markets?." Energy Economics 143 (2025): 108243.

[125]David P. Brown, "The Effect of Subsidized Entry on Capacity Auctions and the Long-Run Resource Adequacy of Electricity Markets," Energy Economics 70 (2018): 205–232, *https://doi.org/10.1016/j.eneco.2018.01.002*

[126]Federal Energy Regulatory Commission, "FERC Order Addresses PJM Capacity Market," June 29, 2018.

[127]Richard Glick, "Commissioner Richard Glick Rehearing Dissent Regarding PJM MOPR," Federal Energy Regulatory Commission, April 16, 2020.

[128]Sylwia Bialek and Burcin Unel, Efficiency in Wholesale Electricity Markets: On the Role of Externalities and Subsidies, CESifo Working Paper No. 8673 (Munich: CESifo, 2020).



4 CONCLUSIONS

Nuclear power presents Ohio with opportunities and challenges that must be balanced. It will likely increase in its importance in the coming decades, as climate change becomes more dire and grid uptime more critical. It is one of a few technologies that can today deliver reliable, carbon-free baseload power: nuclear plants run day and night regardless of weather, produce no carbon emissions, and once built can operate reliably for decades, largely insulated from the kind of regulatory and economic shifts that affect shorter-lived assets.

However, these benefits come with serious financial risks. Construction costs are large and unpredictable, with even smaller plants typically projected at billions of dollars. Development timelines often stretch past a decade, exposing projects to economic conditions that can shift substantially before a plant ever generates power.[129] That long, expensive construction process also means high financing exposure, since every year of delay adds interest costs and pushes back the point at which investors recoup their money. Decommissioning is its own major expense, running into hundreds of millions of dollars per site, far above other generation types, which range from roughly $15,000 per megawatt for gas plants to $212,000 per megawatt for offshore wind.[130] Likewise, the Price-Anderson act limits the amount of insurance a utility must carry for catastrophic events, leaving citizens and ratepayers potentially responsible.

This risk profile is precisely why nuclear power has struggled to gain traction in Ohio's deregulated market. In a competitive market, investors are the ones who bear construction and financing risk, and they weigh that risk against other uses of their capital, which is exactly what has made nuclear a hard sell without some other backstop. Ohio proposed House Bill 862 supplies such backstop. By reregulating nuclear generation and allowing it back into a utility's rate base, the bill lowers utilities' exposure to construction risk and guarantees them a rate of return on their investment. The effect is to move financial risk off of investors and onto ratepayers, who become responsible for costs even though they had no role in deciding whether or how the plant was built. This is the bill's central policy shift. It functions, in practice, as a subsidy: utilities are relieved of the market discipline that would otherwise force them to absorb the cost of their own inaccurate projections. And it allows them to sell power at below market rates to attract power purchase agreements, since much of the cost of generation will be deferred, socialized and collected later from the ratepayers.

Ohio has seen this movie before. In the 1970s and 80s, Ohio utilities build three nuclear power plants (one abandoned before it ever started) that incurred massive cost overruns which were mostly socialized throughout the rate base. The utilities simply passed through their costs to the ratepayers. The more it

[129]U.S. Department of Energy. " Walk Me Through It: A Step-By-Step Guide for Consumers Going Solar." *https://www.energy.gov/cmei/systems/articles/walk-me-through-it-step-step-guide-consumers-going-solar. Accessed June 18, 2026.*

[130]Raimi, Daniel. "Decommissioning US power plants." Decisions, costs, and key issues. Resources for the Future (RFF) Report (2017).

spent on capital, the more money the utilities made, with virtually no risk. That regulatory regime led to rising electricity costs and eventually the departure of manufacturing and industrial jobs from Ohio.

In response to this problem, the state deregulated electricity in 1999. In so doing, it separated the accounting for generation from the accounting for distribution, so that generation could become competitive while distribution remained a regulated monopoly. That separation is necessary for a competitive generation market to function, but it isn't sufficient. When generation and distribution assets are affiliated or share ownership, utilities have an incentive to recategorize generation costs as distribution costs, including through broad rate riders that blur the line between the two. House Bill 15 was passed in 2025 in part to curb utility exploitation of cross subsidies.

Ohio utilities now seek to reregulate nuclear generation and have offered up proposed HB 862 as one strategy to do this. It seeks to mitigate some of the risk by requiring 20-year power purchase agreements from end users. But there is no way around the fact that HB 862 shifts the risk from the utility to the ratepayers. It just defers some of the costs, which will be carried by the utility at its usual 9-10% rate of return. HB 862 would burden the PUCO with policing cost accounting, ascertaining market value, and making prudency decisions – all while the utilities have a significant technical and information advantage.

The broader problem is that subsidizing any single generation technology sits uneasily with the goal of a competitive electricity market. FERC has been wrestling with this problem in managing the capacity auctions and ultimately determined to require that utilities add subsidies into their bids so that they do not discourage others from bidding. The result is that ratepayers pay the subsidy twice. Ohio will face the same problem FERC did in its own retail marketplace.

Subsidies can be a legitimate tool for correcting market failures, such as the failure to account for carbon dioxide emissions. Propping up one generation method, however desirable its underlying benefits, necessarily comes at the expense of a level playing field for the rest of the market. For Ohio ratepayers, then, the real question raised by HB 862 is not whether nuclear power can deliver reliable, clean electricity, but whether it is fair to ask ratepayers, rather than investors, to absorb the risk when nuclear projects run over budget.

Ultimately, Ohio policy makers will have to do a cost-benefit analysis that looks at the complex problems associated with large scale energy subsidies. This will include consideration of some of the following findings from this Study:

Nuclear power is reliable. While wind sometimes does not blow and light does not always shine, nuclear power plants can run day and night and irrespective of the weather. This helps residents and businesses have access to power regardless of external conditions.



Nuclear power is carbon-free. Like wind and solar, nuclear energy generation does not emit carbon, helping to decarbonize Ohio's energy grid and reducing the state's contribution to global climate change.

Nuclear power is long-lived. Nuclear power assets can be maintained for many decades, making nuclear power a source that, once constructed, can be reliable for generations.

Nuclear power has large construction costs. Nuclear power plants are typically projected to cost hundreds of millions of dollars to build and end up costing billions of dollars – four times the cost of other generation. This makes nuclear power a significant financial obligation for those who finance it.

Nuclear power is developed over long timelines. While solar panels can go through permitting and installation in a few months, nuclear power projects often take over a decade to develop and construct. Economic changes over this time make long-term planning crucial and unpredictable changes in markets problematic for nuclear projects.

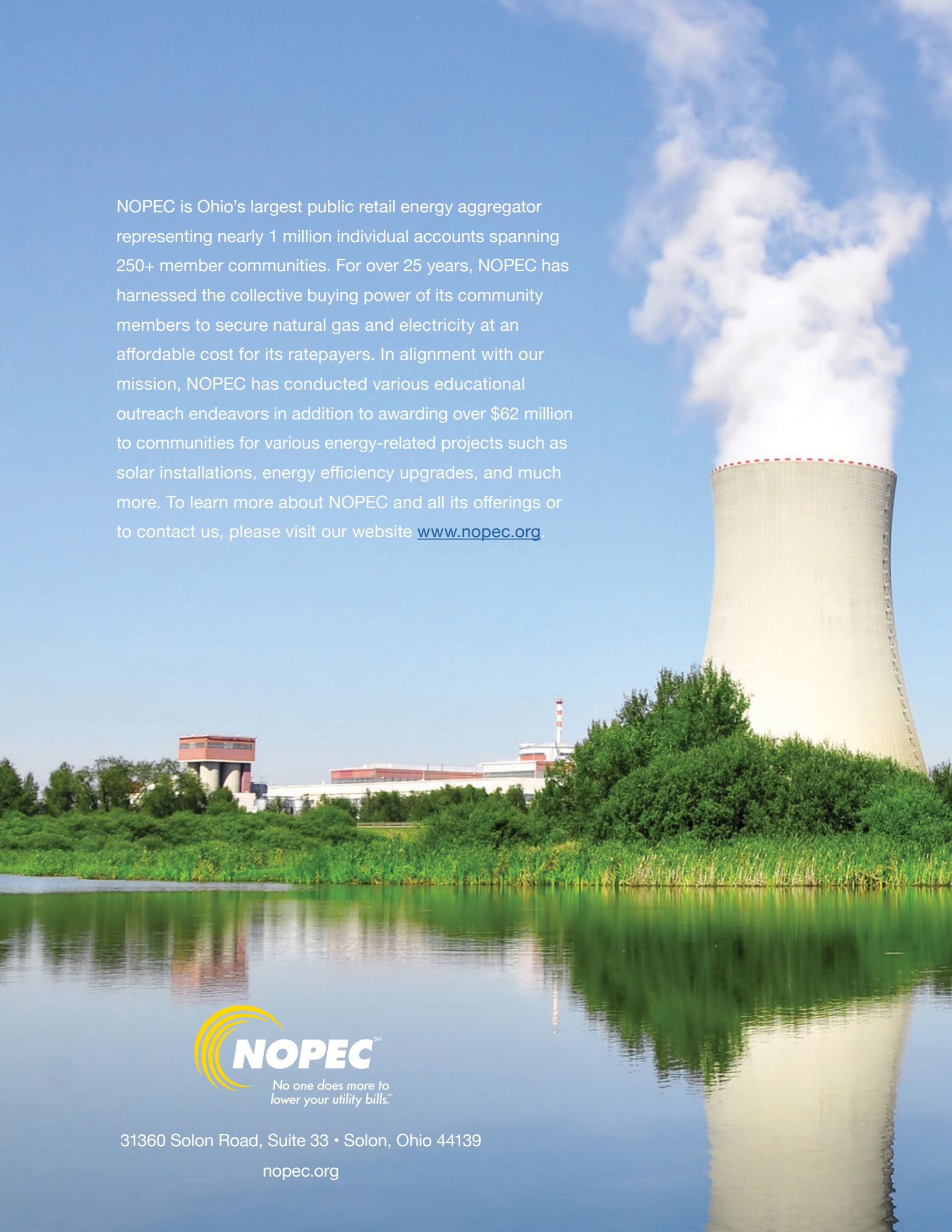
Nuclear power has high financing exposure. The combination of high up-front costs and unpredictable construction timelines leads to high exposure for investors in nuclear energy projects. Every additional year of delay leads to more interest being paid by investors and longer time until investments can be recouped.

Nuclear power has major decommissioning obligations. Nuclear energy generation sites cost hundreds of millions of dollars to decommission, taking a bite out of returns to investment in nuclear projects. Decommissioning nuclear power is much more expensive than other sources of power, which range from $15,000 per megawatt for gas plants to $212,000 per megawatt for offshore wind.

Nuclear power has a history of overruns. Ohio's nuclear power plants have all experienced overruns of 250% or more, and this is typical of nuclear power plants across the country.

Subsidies of Nuclear Power threaten Ohio's deregulated energy market. Ohio ratepayers have saved nearly $3 billion/year – around $0.02/kWh – as a result of deregulated markets. Reregulating nuclear power will distort and destabilize the generation markets that have been so effective in Ohio, discouraging commercial retail service companies from bidding on Ohio loads.

Distribution owned generation encourages cross subsidy accounting. When distribution and generation projects can be affiliated or share ownership, incentives are aligned for companies to categorize generation expenses as distribution expenses. Distribution utilities will seek distribution riders that benefit their generation but spread the cost throughout the distribution rate base.



NOPEC is Ohio's largest public retail energy aggregator representing nearly 1 million individual accounts spanning 250+ member communities. For over 25 years, NOPEC has harnessed the collective buying power of its community members to secure natural gas and electricity at an affordable cost for its ratepayers. In alignment with our mission, NOPEC has conducted various educational outreach endeavors in addition to awarding over $62 million to communities for various energy-related projects such as solar installations, energy efficiency upgrades, and much more. To learn more about NOPEC and all its offerings or to contact us, please visit our website www.nopec.org.

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