DECLARATION OF RIC O'CONNELL, MICHAEL O'BOYLE, AND BRENDAN PIERPONT IN SUPPORT OF ENVIRONMENTAL AND PUBLIC HEALTH RESPONDENT-INTERVENORS

We, Ric O'Connell, Michael O'Boyle and Brendan Pierpont, jointly declare as follows:

Qualifications

1. I, Ric O'Connell, am the Executive Director at GridLab, a nonprofit organization that provides expert capacity and thought leadership to address technical challenges as the grid transitions to clean energy. I have performed numerous studies on power systems reliability, renewable energy integration, project economics, and transmission planning for over 20 years. I have significant professional experience with modeling future power systems, and have published many widely read reports and analysis on current and future power systems. I was an executive and engineer at Black & Veatch for 12 years, where I performed engineering design and diligence on dozens of utility scale solar projects, and assisted several utilities with planning and procuring new resources. In 2005 I earned a Masters in Science from the University of Colorado, Boulder, and in 1990 I earned a Bachelor of Science in Electrical Engineering from Duke University.
2. I, Michael O'Boyle, am Senior Director, Electricity at Energy Innovation, LLC, a non-partisan energy and climate policy think tank that produces independent analysis to inform policymakers of all political affiliations in the world's largest emitting regions. We provide objective, science-based research to policymakers and other decision-makers seeking to understand which policies are most effective to ensure a safe climate future. Our work includes conducting quantitative assessments of how our energy sectors will change as the world moves toward a zero-carbon economy, using those quantitative

assessments to inform policy priorities and policy ambition, and researching lessons about detailed policy design and implementation. We prioritize emissions reduction policies in the largest-emitting nations and largest-emitting sectors, with a focus on policies that accelerate markets for technology-neutral zero-carbon solutions at the speed and scale science says is necessary to confront the climate challenge, while delivering economic, security, and equity benefits. All our recommendations stem from careful research and analysis. I have researched power system transformation at Energy Innovation for 10 years, leading a team to analyze energy policy impacts with a focus on the U.S. electricity sector. We use these insights to publish research and make independent recommendations to policymakers on the policy design to achieve a rapid, affordable, reliable transition to a low-carbon economy. I have published dozens of research reports focused on utility regulation and energy system optimization, several of which have been entered into peer-reviewed journals. I have co-authored studies that use industry-standard system planning and dispatch models to analyze least-cost pathways to reduce emissions from the U.S. grid and have become familiar with the operation and design of these models. I've also contributed the power sector chapters to Energy Innovation's 2018 publication, "Designing Climate Solutions." I have given numerous presentations on regulatory topics and resource economics at state public utilities commissions, including Minnesota, Nevada, Oregon, and Rhode Island, as well as at National Association of Regulatory Utility Commissioners convenings. I have facilitated substantive conversations between utility regulators and industry experts on energy transition, rate design, market design, and financial topics. I am familiar with the technologies, economics, development dynamics, financial incentives, and regulatory environment in which electricity markets operate. I also studied utility regulation pursuing my Juris Doctorate at Arizona State University and was accepted into the Arizona Bar Association in 2014.

3. I, Brendan Pierpont, am Director of Electricity Modeling at Energy Innovation, LLC. I have conducted expert research and analysis of electricity market and policy issues and have over 15 years of experience modeling the economics of electricity sector resources, evaluating utility resource planning analyses, and analyzing electricity sector data and trends. I have authored research reports on electricity sector policy and market issues and have drawn on my expertise to provide research and analysis to policymakers, market participants, and public interest stakeholders. I am familiar with utility integrated resource planning processes and recent plans filed by utilities around the country. I am also familiar with sector-wide electricity trends and the economic forces shaping those trends. I have studied electricity market design, electricity resource adequacy and reliability, coal power plant economics and the economics of power plant pollution control regulation. In 2015 I earned a Master's degree in Management Science and Engineering from Stanford University, with a focus on energy system modeling and analysis.

4. We have reviewed the U.S. Environmental Protection Agency's ("EPA's") rules titled "New Source Performance Standards for Greenhouse Gas Emissions From New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions From Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule," 89 Fed. Reg. 39,798 (May 9, 2024) (the "Rules") and are familiar with their requirements.

Summary of Declaration

5. Our declaration focuses on four facts.

- First, coal economics have been worsening, and as a result coal use in the electricity sector has been rapidly declining since the late 2000s. The aging fleet of coal plants affected by the Rules is increasingly uneconomic and a significant portion of the fleet is likely to retire even without the Rules.
- Second, utilities are unlikely to make significant, irreversible investments in response to the Rules in the next two years. Most of the immediate utility actions under the Rules would be to plan, evaluate, and begin soliciting competitive bids from market participants for replacement generation or retrofit of existing coal units. In the case near-term investments are necessary, they likely do not harm consumers or utilities, due to the nature of utility ratemaking and the cost savings possible from clean replacement, gas co-firing, and retrofits.
- Third, the Rules' compliance timelines give utilities more than enough time to plan for retirement, if they choose that route, by contracting with, developing, and interconnecting new generation resources sufficient to replace those plants.
- Fourth, utilities, regional grid operators, and their regulators have adequate solutions to maintain electric system reliability both in the short-term and in the long-term during implementation of the Rules.

Section 1: Coal use in the electricity sector is rapidly declining, as the aging fleet of coal plants is increasingly uneconomic.

6. The use of coal in the U.S. electricity sector is in the midst of a long-term sustained decline. Coal has decreased from 45 percent of U.S. electricity generation in 2010 to 16 percent in 2023.[1] Of the 342 gigawatts (GW) of coal-fired capacity operating in 2010, 136 GW has retired, and 24 GW of capacity has stopped burning coal as a primary fuel, leaving only 192 GW of currently operating coal-fired power plants.[2]

7. While most coal plants were originally designed to operate as "baseload" resources that operated nearly all the time, this type of operational profile is no longer economically justified as resources with lower operating costs are now available for many hours of the year. As a result, coal capacity factors (the proportion of a plant's average electricity generation to that plant's available generating capacity) have declined significantly over time. The fleet-wide average coal capacity factor has declined from 67 percent in 2010 to 42 percent in 2023, with continued declines in the first quarter of 2024.[3] Even with this decline in utilization, many coal plants still operate at times when their variable costs of operating are greater than the market price for the energy they produce. Since 2015, uneconomic coal plant operations have cost electricity customers $17.8 billion more than the value of energy at market prices during those hours.[4]

8. This decline of coal-fired electricity generation is mirrored by a significant reduction in coal mining volumes and coal mine closures, raising fuel supply

---

[1] EIA, "Electric Power Monthly", https://www.eia.gov/electricity/monthly/
[2] Capacity reflects "Nameplate" capacity rating of generating units. Current capacity includes additions since 2010. Based on analysis of EIA Form 860 data.
[3] EIA, "Electric Power Monthly", https://www.eia.gov/electricity/monthly/
[4] RMI, "Economic Dispatch Dashboard," https://utilitytransitionhub.rmi.org/economic-dispatch/

risks for coal-fired power plants.[5] The decline in coal production directly impacts the considerations of electricity generators. For example, in their 2023 Carolinas Resource Plan filing with regulators in North Carolina and South Carolina, Duke Energy states that delaying coal retirement timing into the mid to late 2030s would mean deteriorating supply conditions for fuel, which would "create future risks for coal supply assurance and ultimately increase reliability and cost risks for customers."[6]

9. Many coal-fired power plants are aging. The average coal plant was built 43 years ago, and by 2032 the average plant will be over 50 years old.[7] As coal-fired power plants age, they become more expensive to operate and maintain. Operations and maintenance costs are roughly 20 percent higher for coal plants between 40 and 80 years old, compared with those between 20 and 40 years old.[8] These high fixed costs, combined with falling utilization and increasingly flexible operations, make many of these plants uneconomic to continue operating relative to other generation resources.[9]

---

[5] According to EIA data, from 2010 to 2023, coal production in the U.S. fell from 1.1 billion short tons to 0.6 billion short tons. While nearly 1,200 coal mines reported active coal production in 2010, by 2022 over half of these were no longer producing coal.

[6] "For Duke Energy, any delays in coal retirement timing, particularly if plant operation is extended into the mid and late 30s, would most likely result in the need for continued coal supply after the coal industry has reduced thermal coal production in response to the utility industry's continued transition away from coal generation. Access to the commodity, the reagents utilized to treat emissions resulting from use of the commodity and transportation have high potential to deteriorate or disappear. These declines in supply availability and market uncertainty create future risks for coal supply assurance and ultimately increase reliability and cost risks for customers. For these reasons, it is extremely important that the Companies plan and execute an orderly energy transition." Duke Energy, "Carolinas Resource Plan: Chapter 1," p. 10. https://www.duke-energy.com/-/media/pdfs/our-company/carolinas-resource-plan/chapter-1-changing-energy-landscape.pdf

[7] S&P Global, "Inflation Reduction Act to accelerate US coal plant retirements," Feb 2023, https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/inflation-reduction-act-to-accelerate-us-coal-plant-retirements-74196498

[8] Sargent and Lundy, "Generating Unit Annual Capital and Life Extension Costs Analysis," December 2019, https://www.eia.gov/analysis/studies/powerplants/generationcost/pdf/full_report.pdf. Sargent and Lundy further found that annual operations and maintenance plus ongoing capital investment totaled $87 per year per kW of capacity for plants over 40 years old, in today's dollars.

[9] NARUC, "Recent Changes to U.S. Coal Plant Operations and Current Compensation Practices", 2020, https://pubs.naruc.org/pub/7B762FE1-A71B-E947-04FB-D2154DE77D45

10. Coal faces increasing economic pressure from other generation sources, primarily wind, solar, battery energy storage, and natural gas. The average cost of utility-scale solar power purchase agreements has fallen over 85 percent between 2009 and 2022[10] and wind power purchase agreements have fallen in cost by over 60 percent.[11] Likewise, the cost of lithium ion battery packs has fallen by over 80 percent in the last 10 years.[12] In 2022, the Inflation Reduction Act (IRA) extended and expanded tax credits for solar, wind and energy storage, driving further cost reductions for new projects. Research from Energy Innovation found that 99 percent of operating coal plants are more expensive to run compared with the cost of new wind and solar generation.[13] Low natural gas fuel costs and improvements in gas turbine efficiency have put further economic pressure on coal-fired power plants over the last decade.

11. Coal's decline is highly likely to continue. Out of the 192 GW of coal plants that remain online today, 36 percent have announced plans to retire or cease burning coal by the end of 2030 or sooner.[14] Estimates from the U.S. Energy Information Agency (EIA), National Renewable Energy Laboratory (NREL), and S&P Global Market Intelligence project coal will account for only 5-10 percent of U.S. electricity generation by 2030, down from 16

---

[10] Berkeley Lab, "Utility-Scale Solar, 2023 Edition", October 2023, https://live-etabiblio.pantheonsite.io/sites/default/files/utility_scale_solar_2023_edition_slides.pdf

[11] Berkeley Lab, "Land-Based Wind Market Report: 2023 Edition," August 2023, https://emp.lbl.gov/sites/default/files/emp-files/land-based_wind_market_report_2023_edition_final.pdf

[12] BNEF, "Lithium-Ion Battery Pack Prices Hit Record Low of $139/kWh," November 2023, https://about.bnef.com/blog/lithium-ion-battery-pack-prices-hit-record-low-of-139-kwh/

[13] Energy Innovation, "Coal Cost Crossover 3.0," https://energyinnovation.org/publication/the-coal-cost-crossover-3-0/

[14] Sierra Club data shows 122 GW of coal remain without plans to retire or cease burning coal through 2030. Sierra Club, https://coal.sierraclub.org/campaign

percent in 2023, with declines driven by economic pressure from lower-cost clean energy sources.[15]

12. In light of these trends, prudent utility practices would include evaluating the economics of continued operation of coal-fired power plants relative to alternatives. In fact, many utilities have already undertaken this type of analysis and developed plans to fully exit coal by 2032 or sooner.

Section 2: Undertaking activities to consider, plan, and procure alternatives is prudent utility practice.

13. Recent changes in technology cost and tax incentives mean that utilities should be evaluating alternatives to their coal generation fleet to serve their customers at least cost irrespective of EPA rules.[16] Those planning exercises take between one to two years, including internal planning, public comment on proposals, and then requests for bids from generators and other technology providers to meet the system needs identified. These planning costs fall in the normal course of business, and utilities can generally recover prudently incurred costs of these planning and procurement processes. Further, those minimal costs would not result in higher electricity rates at a level that would harm state economies.

14. Even in the unlikely case substantial replacement or retrofitting capital expenditures are necessary under the Rule in the very near term, harm remains highly unlikely if utilities allow planning to reveal the least cost

[15] See for example: NREL, "2023 Standard Scenarios: Mid-Case Current Policy Scenario", https://scenarioviewer.nrel.gov/
EIA, "2023 Annual Energy Outlook," https://www.eia.gov/outlooks/aeo/
S&P Global, "Inflation Reduction Act to accelerate US coal plant retirements," Feb 2023, https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/inflation-reduction-act-to-accelerate-us-coal-plant-retirements-74196498

[16] See generally, https://www.analysisgroup.com/globalassets/insights/publishing/2024-electric-utilities-and-the-ira-iija.pdf

option, especially for existing coal-fired power plants without firm retirement dates before 2032.

Over the next two years utilities would only be planning for emissions controls or replacement power, not investing significant amounts of capital. Most utilities undertake this type of planning exercise as part of their normal course of business.

15. Utility rates only change when utilities apply to their regulators or board for review and approval of that change in a rate case. The rate case is a petition to change rates based on projected changes to expenditures. An investment in technology, whether carbon capture and storage (CCS), co-firing, or in a replacement portfolio would not go into rates until expenditures are approved and begin. The costs associated with resource planning and structuring market bids are minimal in the magnitude of the revenue requirement and would not be felt by customers, and likely would not even require a rate case to cover these costs, which are incurred as a regular course of business regardless of the Rules. It would not be necessary to incur large capital expenditures associated with compliance in the next two years.
16. Resource planning is a process that utilities undertake periodically, especially when considering major investments, to determine what is the best option for their customers and business. Most customers are served by utilities whose plans must be approved by state regulators, and cooperatives, municipal utilities, and federal power administrations also have boards that serve a similar function. A utility best practice is integrated resource planning, through which all cost-effective options are meant to be examined over a 10 to 20-year time horizon and subjected to public comment and regulatory approval. Integrated resource plans take less than a year for

utilities to develop internally, then about a year to present, negotiate, and finalize through a public process.

17. We've collectively worked with stakeholders in over three dozen integrated resource planning proceedings over the last five years, and we understand that the modeling and analysis necessary to inform a least cost planning exercise can be done relatively quickly thanks in part to modern computing. GridLab has routinely completed modeling exercises to correct outdated assumptions and promote modern modeling techniques in a matter of months to support a better outcome for consumers, public health, and climate pollution. For utilities, re-running their models with updated assumptions to understand the least cost compliance pathways is feasible, and is a routine cost associated with ongoing planning.

Investment and spending on compliance does not harm electric utilities themselves, or state economies through rate increases, which modeling and analysis have shown are unlikely or minimal.

18. Rising coal costs; low natural gas costs; and falling costs of wind, solar, and storage has already made it prudent for every utility to reassess the economics of running coal past 2032. The rule stimulates this economic evaluation process for utilities that have not examined such alternatives publicly, which is very unlikely to increase rates or harm utilities' businesses over the next two-year period. Furthermore, publicly available data and market trends strongly suggest that this would likely result in lower overall costs to the vast majority of utilities and ratepayers.

19. Though best practice is to plan and optimize under regulatory and public procedure to illuminate least cost solutions to compliance, some utilities may act more quickly and begin investing within the next two years. But

capital expenditures to replace or retrofit old coal plants do not mean rates will increase.

20. Rates are impacted by both the scale of up-front investment, as well as the overall impact on utility costs over the long-term, including savings associated with lower fuel costs or additional CCS-related revenue. New capital expenditures like CCS, co-firing, or replacement generation are not recovered from customers in one lump sum. Any addition to the capital base is collected annually at a rate that reflects the useful life of the asset, plus returns that cover the cost of capital. The degree of cost impact relative to the existing capital base also matters. Generation, the portion of utilities' assets affected by the Rules, accounted for only 26 percent of investor-owned utilities' functional capital expenditures in 2023, with the rest tied up in distribution and transmission.[17]

21. For utilities specifically, new investments are likely a benefit. Monopoly utilities charge their customers the cost of serving them, including the returns required to raise debt and equity capital as applicable. For-profit investor-owned utilities, such as members of the Edison Electric Institute, must submit rate requests for approval by state regulators while municipal, cooperative, and federal utilities have some version of boards that serve a similar function. For-profit utilities see higher returns for shareholders when they increase their capital expenditures under this regulatory framework.[18]

[17] EEI, 2023. Capital Expenditures Summary. https://www.eei.org/-/media/Project/EEI/Documents/Issues-and-Policy/Finance-And-Tax/bar_cap_ex.pdf.

[18] See generally, Steve Kihm et al. *You Get What You Pay For: Moving Toward Value In Utility Compensation, Part 1 – Revenue & Profit*. 2015. https://energyinnovation.org/wp-content/uploads/2014/12/CostValue-Part1-Revenue.pdf

22. Coal plants have a large operational cost in the form of fuel purchases as well as operating expenses like labor.[19] While capital expenditures operate like a sunk, fixed cost on consumer bills, lower coal use immediately leads to a reduction in operating costs. Assuming flat or growing demand for electricity, reductions in coal use would be replaced by new costs in the revenue requirement, with potential savings from cheaper replacement or higher costs from more expensive replacement. Higher rates would only occur if the levelized expenses from replacement or retrofit exceed the savings from burning less coal and/or retiring the plant.

23. Prudent utility planning for least cost compliance would likely reveal many options to avoid large rate increases and even achieve immediate savings when faced with these choices, with especially minimal impacts in the near term. For the plants which have not currently announced retirement dates before 2032, considering and investing in replacement resources does not necessarily result in harm to utilities, their customers, or state economies. In fact, it can be good for economies, utility companies, and customers.

24. A 2023 report by Energy Innovation, the Coal Cost Crossover 3.0, found that after the passage of the Inflation Reduction Act and due to continued cost declines of wind and solar, 99 percent of U.S. coal plants were in 2021 more expensive to simply run than the all-in levelized cost of new local or regional wind and solar power.[20] In ratemaking terms, the all-in cost of wind

[19] While some utilities own coal plants in part or in whole, utilities can also contract on behalf of their customers for energy from coal plants owned by other utilities or independent power producers. Contracts for energy are generally also treated as operational expenditures and roll off the utility balance sheet completely when they expire. In the case of utility cooperatives, contracts between distribution cooperatives and generation and transmission cooperatives (G&T) are symbiotic and function like a sunk cost – the G&T will typically make investments in power plants only when its members agree to cover those costs and take energy from those plants over a period long enough to justify the expense.

[20] Michelle Solomon, Eric Gimon, and Mike O'Boyle. *The Coal Cost Crossover 3.0*. Energy Innovation. 2023. https://energyinnovation.org/wp-content/uploads/2023/01/Coal-Cost-Crossover-3.0.pdf.

and solar power to provide 100 percent of the annual energy of the coal plants examined would be lower than the operational costs and going-forward capital costs of virtually all coal plants.

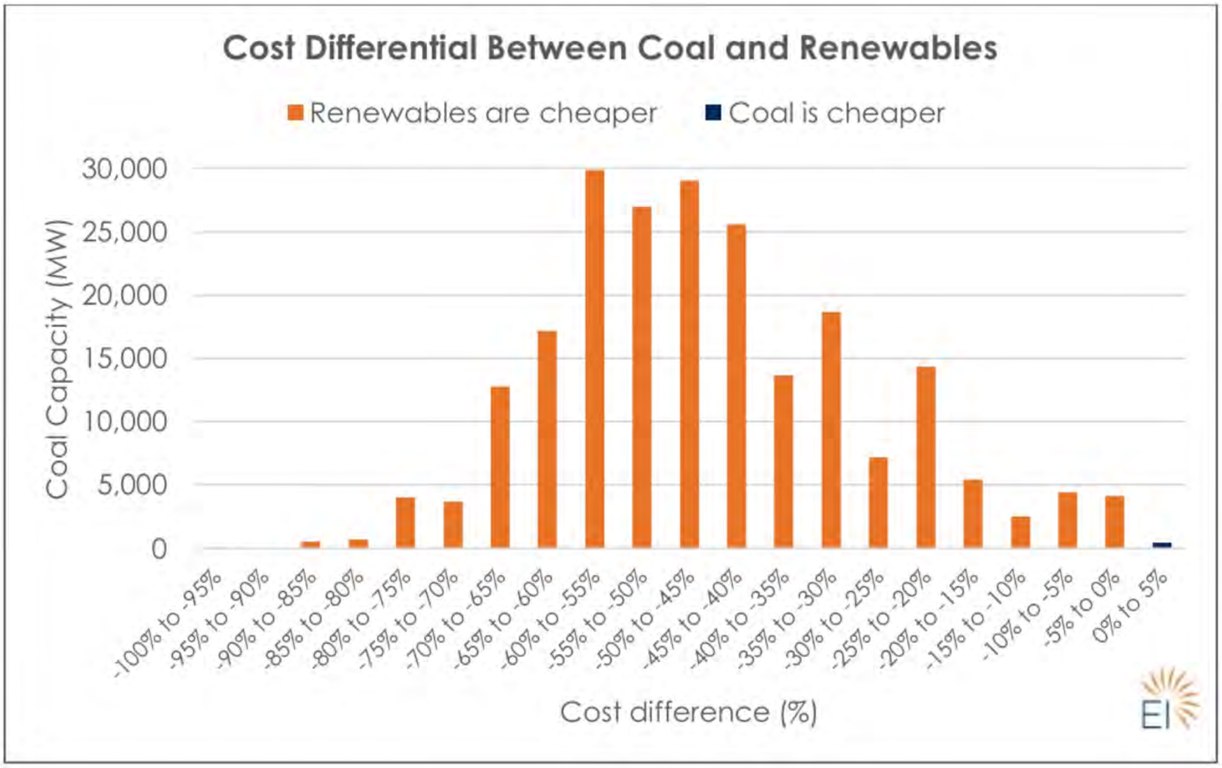

Figure 1. Aggregated plant capacity shown as percent difference between renewables levelized cost of energy (LCOE) and coal going-forward cost. The orange bars indicate capacity where renewables are cost-competitive with coal and coal is deemed "uneconomic." The one blue bar indicates the sole plant that is still cheaper to operate than replace with renewables.

25. Furthermore, coal is not necessary for the reliability attributes it provides. As we discuss in Section 4 below, reliability is a system attribute, and coal does not need one-to-one replacement to ensure the system remains reliable. Because wind and solar are so much cheaper than coal in many parts of the country, these operational savings can be used to pay for complementary resources with high reliability value like battery storage, interregional

transmission, or combustion turbines, often at a savings or minimal ratepayer cost.

26. The Coal Cost Crossover analysis finds the operational savings from switching from coal to wind and solar energy are enough to cover a large portion of the storage costs necessary to make wind and solar just as dependable and dispatchable as coal, again without necessarily raising customer costs. Energy Innovation's Coal Cost Crossover report evaluates the amount of storage capacity that can be financed based on the cost savings from replacing coal with wind and solar, and compares that storage capacity to the capacity of the coal plant. We found that the savings generated by shifting to local solar could fund the addition of 137 GW of four-hour batteries across all plants (65 percent of existing coal capacity). While this analysis reflects 2023 costs, storage costs will likely continue to drop over the next eight years and beyond.[21] New low-capacity-factor natural gas combustion turbines, energy efficiency, and demand response should also be considered as part of an analysis of the least-cost portfolio to replace a coal-fired power plant.

27. Additional savings are possible through good policy design that optimizes customer payments for the stranded coal costs (if applicable) as well as transmission infrastructure associated with replacement projects. On the financial side, though past capital expenditures on the coal plant remain in the revenue requirement until full depreciation, there are opportunities to leverage creative low-capital-cost financing to reduce the total rate impact of

[21] Wesley Cole and Akash Karmakar, Cost Projections for Utility-Scale Battery Storage: 2023 Update. National Renewable Energy Laboratory. 2023. https://www.nrel.gov/docs/fy23osti/85332.pdf

repaying stranded capital investments, including securitization.[22] The analysis also considers some aspects of transmission access relevant to a cost analysis by examining the economics of wind and solar projects within a 45 kilometer radius, finding 199 of the 210 plants still had cheaper replacement options with these locational constraints applied. Clean portfolios of wind, solar, and storage could be installed at existing coal sites, facilitating an even faster, lower cost interconnection and replacement process.[23]

28. For those coal facilities assessing a CCS retrofit, again the full long-term ledger has to be taken into account to assess ratepayer and state economic impacts. In its Rulemaking, EPA provided evidence that on average, CCS plants capturing 90 percent of emissions save customers money after installation because of IRA tax incentives that offer a marginal benefit to consumers of more than $100 per megawatt-hour. Recent government studies of CCS feasibility support this claim.[24] Any effort to install CCS at the state or utility level will be the result of least-cost planning and, if so, will have been selected with this full range of costs and benefits considered.

29. Assessment of natural gas co-firing or full conversion should involve a similar examination of the whole revenue requirement. Additional investments that enable the plant to operate on natural gas should also be measured in conjunction with changes in fuel cost, and the hedging, flexibility, and resilience value that dual fuel operation may provide. For example, a report from Andover Technology Partners submitted to the

---

[22] See generally, Ron Lehr & Mike O'Boyle, Managing the Utility Financial Transition from Coal to Clean. Energy Innovation. 2018. https://energyinnovation.org/wp-content/uploads/2018/12/Managing-The-Utility-Financial-Transition-From-Coal-To-Clean.pdf.

[23] Katie Siegner, Alex Engel. *Clean Repowering: A Near-Term, IRA-Powered Energy Transition Accelerant*. RMI. 2024. https://rmi.org/clean-repowering-a-near-term-ira-powered-energy-transition-accelerant/

[24] https://netl.doe.gov/projects/project-information.aspx?p=fe0031845

record indicates that "natural gas co-firing is advantageous for load following"[25] as compared to only firing coal. Given that the average coal-fired plant operated at roughly a 42 percent capacity factor in 2023[26] and has since fallen, coal is now, and will increasingly be asked to serve this load-following function. The Andover report pegs the incremental capital cost of gas co-firing at around $50 per kilowatt (kW), or about 1-2 percent of the original cost of the plant.[27] The report also highlights examples of co-firing for a range of reasons, including resilience, access to cheaper fuel, and reduced environmental remediation costs. Thus, any costs from implementing this compliance option would be minor, and most of these costs would not occur in the next two years.

Section 3: The timelines for replacement power are sufficient to plan, procure, build, and interconnect resources necessary to maintain a reliable grid under the EPA rule.

30. As covered in the previous section, the main utility activities under this Rule in the next two years will be related to planning. In this section, we provide detailed evidence to demonstrate that if an existing coal plant operator chooses to retire and replace its generation, there is ample time to plan, study, procure, and develop a replacement clean energy portfolio such that significant expenditures and reliability issues would not manifest over the next two years, or even by 2032.

[25] Andover Technology Partners. Natural Gas Cofiring for Coal-Fired Utility Boilers. Commissioned for CAELP. 2022. at p. 7. https://www.andovertechnology.com/wp-content/uploads/2022/02/Cofiring-Report-C_21_2_CAELP_final_final.pdf

[26] EIA data.

[27] There are likely additional costs associated with pipeline construction, which the EPA examined in its Unit-Level Cost and Reduction Estimates for Natural Gas Co-Firing Final Rule. These must be measured against projected fuel costs, and consideration of depreciation schedules must also be taken into account.

31. For utilities that choose to comply with the rule by retiring coal plants and replacing them with cleaner portfolios, the rule requires compliance by 2032, or about seven and a half years from when the rule enters force in July 2024. Projects in the interconnection queue today can be helpful – utilities are not starting from a standstill when looking to develop new projects. Aggregated data from regional "interconnection queues" suggest that ample resources are shovel-ready to replace coal generation on an expedited timeline. While the time to get through this queue has increased over time, so have the interconnection agreements already approved. Currently, 311 GW of resources in the queue have either drafted or completed their interconnection agreements, signaling they are ready to execute contracts and begin commercial development, according to a Lawrence Berkeley National Laboratory (LBNL) study published in 2024.[28] Around 300 GW of additional wind, solar, storage, and gas resources are in the final study stage, the facility study, which the Federal Energy Regulatory Commission (FERC) estimates takes 90-180 days.[29]

32. Considering 861 projects across six regional grid operators, the LBNL study found that the average project from 2016-2023 reached commercial operation an average of 25 months after interconnection agreement execution, with moderate regional variability outside of the California Independent System Operator (CAISO).[30] In other words, several hundred GW of projects can likely reach commercial operation within the next three years.

[28] Rand et al. *Queued up: 2024 Edition*. Lawrence Berkeley National Lab. 2024. https://live-etabiblio.pantheonsite.io/sites/default/files/queued_up_2024_edition_r2.pdf

[29] Rand et al., 2024.

[30] LBNL's dataset did not have data for the non-ISO regions, the West and Southeast, but specific utility timelines back up the national LBNL dataset for utilities in these regions as well. Because California utilities already are coal-free and not planning on building new gas, this timeline analysis does not apply to them.

33. The queue data shows there are hundreds of gigawatts of electric generation capacity, spread relatively equally between major grid regions, that either currently or will soon complete their interconnection agreements, and therefore will be available for procurement and operation an average of two years from now. For reference, fewer than 200 GW of coal plants are online today. The precise amount of replacement resources available under current and pending interconnection agreements will vary from region to region, but the sheer magnitude of projects already completed demonstrates that utilities can replace coal as new resources are brought online. Each regional market examined by LBNL is replete with resources that have completed the technical requirements to enter into operation much sooner than 2032.
34. Over the next year, two recent FERC rules will take effect and further reduce barriers to rapid deployment of cost-effective replacement resources. FERC Order 2023 required regional grid operators and utilities to modernize their interconnection study procedures and finish them more quickly or face fines. These rules will reduce the incremental cost of interconnection for new resources and promote transmission investments that facilitate larger batches of resources to connect. FERC Order 1920 requires regions to update their regional transmission planning practices to consider an expanded set of consumer benefits and account for the economic benefits of new generation options as well.
35. For an example of how utility planning and procurement works in practice, the Northern Indiana Public Service Company (NIPSCO), which serves 480,000 electricity customers in Northern Indiana and is in the Midcontinent Independent System Operator (MISO), completed its integrated resource plan in 2021. It expects to cost-effectively bring 400 megawatts (MW) of wind capacity, 1,485 MW of solar capacity, and 135 MW of storage capacity

online by 2025 to replace aging coal plants – a matter of four years.[31] NIPSCO has set a target of zero coal-fired generation by 2028, compared to 75 percent of the utility's generation mix from coal in 2018.

36. Specific utilities outside of the independent system operator (ISO) regions have also managed to plan for coal retirement and replacement in far fewer than seven and a half years. For example, Duke Energy Carolinas' recent 2023 request for proposals (RFP) for new solar and storage will take an estimated 14 months, and requires respondents to enter service "within three years following the end of the contract phase," a total just over 4 years after planning concluded.[32] The 2022 RFP of Tri-State, a large generation and transmission cooperative utility in Colorado, New Mexico, Nebraska, and Wyoming – the output of a two-year planning and settlement process – also required procurement to replace retiring coal generators for "projects with commercial operation dates on or before December 31, 2025 . . . [and may consider] highly competitive bids with commercial operation dates in 2026."[33] This process will procure sufficient resources in a four-year period to replace multiple large retiring coal plants. In 2021, Public Service Company of New Mexico issued RFPs for a resource portfolio to replace its retiring coal-fired San Juan Generating Station, requiring "a planned project in-service date of no later than December 31, 2024."[34] In June 2024, Entergy

[31] 2024 NIPSCO Integrated Resource Plan, First Stakeholder Meeting Presentation. April 23, 2024. https://www.nipsco.com/docs/librariesprovider11/rates-and-tariffs/irp/presentation-april-23-2024.pdf?sfvrsn=8fd3e151_9.

[32] Duke Energy Carolinas, 2023 Solar and Storage Paired with Storage Procurement: Request for Proposals for New Solar Resources. 2023. https://www.dukeenergyrfpcarolinas.com/Portals/0/Documents/RFPDocuments/23_RFP_Document_7-31-23_corrected_1-8-24.pdf.

[33] Tristate RFP, 2022. https://tristate.coop/2022rfp.

[34] PNM RFP. 2021. https://www.pnm.com/documents/396023/23816266/PNM+2021+Replacement+Generation+RFP+Instructions+to+Bidders-Final.pdf/9dedc8fb-5a06-7d79-70c9-3e3abb544391?t=1614793768977. While the projects selected to replace San Juan Generating Station were delayed, the final project is expected to be online in July 2024, within the initial requirements of the RFP.

Texas applied for approval of two new hydrogen-capable gas power plants expected to come online by mid-2028, in just four years. Notably, Entergy's proposed plants are designed to allow for streamlined retrofits with CCS equipment and the ability to run entirely on hydrogen fuel to enable compliance with the Rules.[35]

37. Natural gas conversion or co-firing is another option for compliance. An example from Gulf Power shows how quickly this can be done. In 2019 Gulf Power approved plans to convert the last remaining coal units at the Crist Coal Plant to natural gas, with a "project timeline show[ing] permitting beginning by May of [2019], construction beginning in early 2020 and the pipeline in service by mid 2020."[36] Gulf Power's parent utility said in a press release that it would make its energy "much more affordable."[37] With this plan including the construction of an entirely new 38-mile pipeline, it demonstrates that conversion including pipeline extension can happen quickly, and in at least some cases, at a significant cost savings when compared to continuing to operate an aged coal facility.

---

[35] "Finally, the sustainable qualities of the Dispatchable Portfolio - specifically, enabling the future use of CCS technology at Legend and utilizing turbines capable of hydrogen co-firing at both resources - will protect all ETI customers by ensuring these major investments are positioned to provide reliable and economic power over their full useful lives notwithstanding current and future federal environmental regulations, including the recently finalized rule under Section 111 of the federal Clean Air Act that will impose significant carbon emission reductions starting in January 2032." Entergy Texas, Inc., Application of Entergy Texas, Inc., Docket No. 56693, Public Utility Commission of Texas, June 2024, https://interchange.puc.texas.gov/Documents/56693_2_1400290.PDF

[36] NorthEscambia.com, "Gulf Power Considering Conversion Of Plant Crist To Natural Gas, Pipeline Through North Escambia," 2019, https://www.northescambia.com/2019/02/gulf-power-considering-converting-plant-crist-to-natural-gas-pipeline-through-north-escambia

See also: Gulf Power Company. Docket No. 20200242-EI. Staff's Third Data Request Request No. 1. December 18, 2020. https://www.floridapsc.com/pscfiles/library/filings/2020/13638-2020/13638-2020.pdf

[37] https://newsroom.nexteraenergy.com/FPL-ends-coal-fired-power-generation-in-Florida-continuing-its-efforts-to-build-a-cleaner-more-resilient-and-sustainable-energy-future?l=12

Section 4: Reliability won't be threatened by the rule in the next two years, or in the long run. Portfolios of coal with CCS, coal co-firing with gas, new low-utilization gas, solar, wind, and battery storage can meet peak loads and expanding load growth, offsetting the reliability contributions of coal that will retire or retrofit in the 2030s.

38. Near-term decisions to replace generating resources will not threaten grid reliability, as portfolios integrating existing fossil fuel resources, retrofits such as CCS or gas co-firing, new low-utilization gas generation, solar, wind, and energy storage can meet growing demand, provide energy and grid services where and when they are needed most, offsetting the reliability contributions of coal plants that may retrofit or retire in the 2030s.

The Final Rule will not compromise reliability in the near-term.

39. While initial activities toward compliance with the Rule will begin soon, the focus of those activities over the next several years will be planning the best path for compliance with the rule and initiating procurement processes. As a result, changes to the resource mix on the grid that are specifically driven by the Rule will be minimal over the next two years. Most of the near-term changes to the operations of the grid, forthcoming retirements and new resource additions, are driven by decisions that were made before the rule was finalized.

40. While some stakeholders have expressed concerns about reliability, in fact near-term reliability risks have eased somewhat over the past several years. In 2021 and 2022, the North American Electricity Reliability Corporation (NERC) published Summer Reliability Assessments (SRAs) that identified regions at high risk of shortages under normal weather conditions, including

the grid region encompassing California in 2021 and the Midwest Independent System Operator (MISO) in 2022, and widespread reliability risks under above-normal temperatures and electricity demand.[38] NERC's Summer Reliability Assessment for 2024 finds much lower levels of reliability risks overall, and highlights the significant role that new solar, battery, demand response and other resources have contributed to addressing regional reliability needs. For example, NERC states:

- "New resources including 25 GW of nameplate solar capacity have been added to the [bulk power system] since last summer. Resource additions in assessment areas that were identified as at risk in the 2023 SRA have largely outpaced rising demand forecasts and resulted in higher on-peak reserve margins." [39]
- MISO: "New solar and natural-gas-fired generation and additional demand response (DR) resources are offset by generator retirements, lower firm imports, and increased reserve requirements. MISO is expected to have sufficient resources, including firm imports, for normal summer peak demand."[40]
- WECC-California: "New solar and battery resources are contributing to higher on-peak reserve margins (46.7%, up over 11 percentage points since 2023) for the upcoming summer. Winter precipitation and snowpack have alleviated drought conditions across California, making more output from the area's hydropower

---

[38] NERC, Summer Reliability Assessment 2022, https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2022.pdf
NERC, Summer Reliability Assessment 2021, https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC%20SRA%202021.pdf
[39] NERC, Summer Reliability Assessment, 2024, , p 6https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2024.pdf, p 6
[40] Ibid, p 5

resources available to balance variability in wind and solar output."[41]

41. Electricity markets and utilities have also demonstrated their ability to meet growing demand, without depending on the types of resources that could be impacted by the Rules. For example, while peak electricity demand has grown by over 10 GW in Texas's competitive ERCOT electricity market,[42] the region has added 2.8 GW of gas-fired combustion turbines, 4 GW of battery energy storage, 12.6 GW of onshore wind, and 14.9 GW of solar capacity since 2020, while only adding 0.2 GW of high-capacity factor combined cycle gas plants over the same time period.[43]

42. Electricity utilities and markets have proven that they are up to the task of maintaining system reliability, building resources that are needed to meet growing demand and replace retiring generators. As the rule does not require existing coal plants or high utilization gas plants to meet a CCS-based standard until 2032, the near-term resource mix – and therefore grid reliability outcomes – will not be affected by the rule. Nevertheless, regional grids around the country are mitigating near-term reliability risks, primarily through accelerating deployment of solar, energy storage, demand response, and in some cases peaking gas resources.

"Baseload" fossil fuel power plants are not needed for reliability; portfolios of low-cost wind and solar, storage, low-utilization gas plants, and improved regional coordination can meet the reliability needs of the grid.

43. Retiring fossil fuel power plants do not need to be replaced one-for-one with another "baseload" dispatchable fossil fuel power plant. This notion

[41] Ibid. p. 5
[42] ERCOT, via GridStatus
[43] EIA Form 860m.

mischaracterizes utility resource planning and electricity market best practices and recent trends.

44. Existing coal-fired power plants, as they are operated today, would not be considered “baseload.” While the term “baseload” generally refers to plants that run at high capacity factors to meet the minimum daily demand, many coal plants are no longer operated in this way. The average annual coal capacity factor has declined to 42 percent in 2023,[44] while only 7.5 GW of the 192 GW of coal online operated at a capacity factor of more than 80 percent in 2023.[45] 85 GW, roughly 45 percent of the operating coal fleet, operated at a capacity factor less than 40 percent in 2023.[46] Rather than operating as always-on generators, most coal plants are offline for many days or months at a time when cheaper resources are available and are used more sparingly during periods of high demand or when cheaper generation options are not available. Recognizing this change in operational profile, several utilities have opted to move their coal-fired power plants to seasonal operations, keeping plants offline for large portions of the year and operating them infrequently to meet peak electricity demand.[47]

45. It is not necessary to replace a retiring coal-fired power plant or meet growing electricity demand with high-capacity factor gas plants. Modern resource planning for a reliable grid requires evaluating the system’s reliability needs and optimizing a portfolio of resources to meet those reliability needs. Each utility or regional electricity market is made up of a

---

[44] EIA, “Electric Power Monthly”, https://www.eia.gov/electricity/monthly/
[45] Analysis based on EIA Form 860m and EIA Form 923.
[46] Analysis based on EIA Form 860m and EIA Form 923.
[47] For example, Arizona Public Service began operating its Four Corners coal power plant seasonally in 2023. Arizona Public Service, "APS announces plans for seasonal operations at Four Corners Power Plant”, 2021 https://www.aps.com/en/About/Our-Company/Newsroom/Articles/aps-announces-plans-for-seasonal-operations-at-four-corners-power-plant

portfolio of many assets, including gas, nuclear, hydro, wind, solar and energy storage. Each asset has its own economic profile, operational considerations, and contribution to the system's reliability needs. Resource planning assembles a portfolio of resources that balances reliability, affordability, and other regulatory or policy goals, much like a diversified financial portfolio reduces risk to an investor. If a utility is facing the need for new capacity to replace a retiring asset or meet growing demand, it is often more cost effective and lower risk to meet that need with a combination of resources including low-cost sources of energy that may be variable, like wind or solar, flexible and fast-responding resources like battery energy storage, and resources that are run infrequently at times during the highest needs on the grid.

46. "Baseload" power plants are not necessary for real-time operational reliability of the electricity system. Electricity grids need resources that can continuously balance supply and demand, react to unexpected changes on the grid like power plants or transmission lines suddenly tripping offline, and otherwise provide grid stability. However, there are numerous ways to supply those real-time reliability services, often with better performance than inflexible coal power plants.[48]

47. Numerous utilities and regional grid operators have shown how portfolios of diverse resources can meet grid needs. For example, in the face of increased load growth in its service territory, Georgia Power proposed a portfolio of

[48] These grid services and the ability of new and existing resources to provide them are summarized in Energy Innovation, "Maintaining A Reliable Grid Under EPA's Proposed 111 Rules Restricting Power Plant Emissions", November 2023, https://energyinnovation.org/publication/maintaining-a-reliable-grid-under-epas-proposed-111-rules-restricting-power-plant-emissions/

See also Milligan, M. "Sources of Grid Reliability Services," 2018, https://www.sciencedirect.com/science/article/pii/S104061901830215X combustion turbines, battery energy storage, and solar.[49] As mentioned above, Texas's competitive electricity market has seen peak electricity demand has grown by over 10 GW,[50] while the market has added 2.8 GW of gas-fired combustion turbines, 4 GW of battery energy storage, 12.6 GW of onshore wind, and 14.9 GW of solar capacity since 2020, while only adding 0.2 GW of high-capacity factor combined cycle gas plants over the same time period.[51]

48. Utility planning and regional market activity shows that high-utilization gas plants simply are not necessary to replace retiring coal plants, many of which are currently operated as low-load or intermediate-load resources. Undertaking planning and procurement activities that limit the role of gas generation without CCS to a 40 percent capacity factor by 2032 will not compromise reliability.

Many utilities and electricity market operators plan to meet electricity system reliability needs without high-utilization gas plants or coal plants without CCS or gas co-firing.

49. Utilities around the country are planning generation portfolios that end the use of coal without CCS by 2032 and avoid building new high utilization combined cycle power plants. In many cases, these utilities developed their plans prior to the EPA's proposed rules, and in some cases, before the passage of the Inflation Reduction Act, which significantly improved the economics of new clean energy resources.

---

[49] GA Power 2023 IRP Update
[50] ERCOT, via GridStatus
[51] EIA Form 860m.

50. Today, several large regions of the country operate with little or no coal-fired generation.[52] In addition, 24 utilities across the U.S. that currently operate coal-fired power plants have resource plans that would end the use of coal, or retrofit existing coal with CCS, by 2032 or sooner. Collectively these utilities provide over 10 percent of U.S. electricity. Taken together, these utilities plan to retire 27 GW of coal-fired generating capacity by 2032 and meet grid needs by 2032 with 56 GW of solar, 22 GW of wind, 15 GW of energy storage, and 18 GW of gas-fired generation capacity, the majority of which is combustion turbines intended to run infrequently.[53] A subset of these utilities are planning to meet future reliability needs with no new high-utilization combined cycle gas plants, as shown in table 1 below.

Table 1: Utilities with plans to end the use of coal without CCS or gas co-firing by 2032, without new high-utilization combined cycle gas

			Capacity Retirements, Conversions, and Additions by 2032							
Name	**Demand (TWh)**	**Coal Date**	**Coal Rets./ Convs.**	**Other Rets.**	**Solar**	**Wind**	**Energy Storage**	**DSM**	**Gas**	**Other**
Florida Power & Light	123.1	2029	-717	-44	18,774	0	2,322	0	255	0
DTE	41.5	2032	-4,336	-70	5,000	1,000	780	51	0	0
Northern States Power Co (Xcel)	39.9	2030	-1,705	-1,064	1,485	4,950	1,210	1,901	2,767	0
Public Service Co of Colorado (Xcel)	28.9	2031	-2,549	0	1,969	3,407	1,170	0	628	19
Entergy Arkansas	22.3	2030	-1,194	-522	3,430	1,500	200	0	447	0
LADWP	20.8	2025	-1,200	-911	2,196	541	515	411	2,111	140
Public Service Co of Oklahoma	18.2	2026	-465	-79	2,100	2,800	0	75	0	0
Indiana Michigan Power	17.2	2028	-2,123	0	1,300	800	315	-3	750	0
NIPSCO	15.6	2028	-1,191	-155	1,965	204	270	0	353	0
AES Indiana	13.0	2025	-1,487	-233	1,843	650	310	372	0	0
Wisconsin Power & Light	11.2	2026	-1,003	0	764	0	0	0	0	0
Great River Energy	10.7	2031	-1,050	0	200	1,171	202	0		0
Mississippi Power	9.3	2028	-502	-474	0	0	0	0	0	0
Public Service Co of NM	9.2	2031	-200	-146	1,405	400	1,474	20	0	0
Total	**381**		**-19,722**	**-3,698**	**42,431**	**17,423**	**8,768**	**2,827**	**7,311**	**159**

[52] California, New York and New England, and several large utilities like Florida Power and Light reliably operate large electricity systems with little or no coal-fired power plants. Taken together these regions constitute 15 percent of U.S. electricity supply.

[53] Based on analysis of data from EQ Research and review of integrated resource plans.

Sources and Notes: Based on EQ Research data, EIA data and review of utility resource plans. Gas includes only low-utilization combustion turbines, uprates of existing combined cycle plants, and new combined cycle plants that will burn hydrogen by 2032 (LADWP). DSM refers to demand side management. Demand expressed in terawatt-hours (TWh).

51. Several of the nation's largest utilities are planning to end use of coal without CCS or gas co-firing by 2032. For example, the largest retail utility in the U.S., Florida Power and Light, plans to retire over 700 MW of coal by the end of 2028, build no new gas power plants beyond small capacity improvements at existing plants, and meet growing electricity demand with 19 GW of solar and over 2 GW of energy storage by the end of 2032.[54] Other utilities planning to retire or convert coal by 2032 and avoid building new high utilization combined cycle gas plants include DTE Electric in Michigan, Xcel Energy in Minnesota and Colorado, Entergy Arkansas, Public Service Company of Oklahoma, Indiana Michigan Power Company, AES Indiana, Great River Energy (a generation and transmission cooperative), and Public Service Company of New Mexico.

52. Regional market operators are also accounting for a significant transition in generation resources. For instance, MISO conducts a scenario development exercise to inform the grid operator's transmission planning and reliability assessment processes. Scenarios developed in this study consistently emphasize a transition away from coal power, minimal new gas, and a significant build-out of solar, wind and energy storage to meet demand.[55]

53. Utility planning emphasizes meeting the reliability needs of the grid, and these utilities are no exception. All the utility resource plans summarized above involve forecasting electricity demand growth, ensuring adequate capacity to meet that demand even under times of stress, and accounting for the reliability contribution of solar, wind and battery energy storage. Many

[54] FPL, "Ten Year Site Plan: 2024-2033" https://www.fpl.com/content/dam/fplgp/us/en/about/pdf/ten-year-site-plan.pdf

[55] MISO, "MISO Futures Report" November 2023, https://cdn.misoenergy.org/Series1A_Futures_Report630735.pdf

of these plans also stress-test their portfolios against extreme weather conditions to ensure that they can perform well even under exceptional circumstances.[56]

[56] Several examples of reliability analyses performed by these utilities are detailed in Appendix A of Energy Innovation, "Maintaining A Reliable Grid Under EPA's Proposed 111 Rules Restricting Power Plant Emissions", November 2023, https://energyinnovation.org/publication/maintaining-a-reliable-grid-under-epas-proposed-111-rules-restricting-power-plant-emissions/