The National Rural Electric
Cooperative Association

Comments on

Proposed Federal Implementation Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standard

Submitted Electronically to:

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by

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Executive Summary

EPA proposed a landmark Federal Implementation Plan (FIP) rule addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standard (the Proposed FIP or Proposed Rule). The Proposed Rule would mandate unprecedented nitrogen oxides (NOx) reductions during the summer ozone season. All or a very significant portions of 42 gigawatts (GW) of coal-fired electric utility generation (EGU) capacity within the 25 states addressed in the FIP will likely be forced to cease operation in 2026 because the alternative option of installing additional emission controls cannot be achieved under the Proposed Rule's timelines. Additionally, the costs of doing so are excessive and far above EPA's cost estimates of "maximized cost effectiveness" making the option infeasible for many units especially with limited remaining lives. Also, beginning in 2023, existing reliable EGU coal-fired generation already equipped with the best emission control technology available will be effectively limited in operation based on their 2021 utilization rates. EPA proposes these changes to take effect next year, with the largest impacts in 2026 – just four years away.

Meanwhile, there is no answer as to how America's power grid can reliably sustain such drastic and rapid changes as the Proposed Rule portends. The current shifts to intermittent renewable generation and retirements in coal-based baseload generation have been and continue to exert pressure on electric reliability. Power interruptions are well-documented in recent years – particularly when load swells during summertime extreme heat events during the ozone season. Aging transmission infrastructure contributes to this dire situation. All the while, Americans expect reliable and affordable power – despite these stark realities.

National Rural Electric Cooperative Association (NRECA) CEO Jim Matheson testified to the Senate Environment and Public Works Committee in March 2022:

> As our nation works to strengthen energy security and reliability while also protecting the environment, we must realize that it is not an all-or-nothing choice
>
> . . . We can address these priorities—but it requires technology and time beyond what is currently available and what many have called for.[1]

[1] Testimony of Jim Matheson, NRECA CEO, on March 23, 2022, to the Senate Environment and Public Works Committee at https://www.epw.senate.gov/public/index.cfm/hearings?ID=79279D16-E2C3-4DAF-80C9-C1DFEFF5860F

Federal Clean Air Act (CAA) programs addressing traditional emissions reductions and greenhouse gas mitigation to address climate change are priorities but must be balanced with the ability of the power sector to deliver reliable, safe, and affordable electricity.

The Proposed FIP is legally tenuous. EPA relies on the “good neighbor” provisions of the CAA Section 110 as the basis for the Proposed Rule. However, Congress did not issue EPA unfettered authority when it crafted Section 110 – which is actually directed toward *state implementation* of emission reduction programs. The magnanimous scope of the Proposed FIP is completely outside EPA’s boundaries of the agency’s rulemaking authorities, as it will have a dramatic impact beyond the CAA and on the energy sector, generation mix, and the ability of 84 million Americans effected by this FIP if implemented to receive reliable and affordable electricity. This Rule is beyond the authority granted to EPA in the CAA. Many of EPA’s presumed authorities in proposing the Rule are expressly reserved for other agencies. For example, Congress put in place safeguards to ensure grid reliability, charging the Federal Energy Regulatory Commission (FERC) and North American Electric Reliability Corporation (NERC) to act as watchdogs. In this Proposed FIP, EPA cuts out these organizations and attempts to step into their roles.

The Proposed FIP is also technically tenuous. EGUs comprise a small portion of downwind state impacts on a sector-basis. Regardless, EPA justifies the need for extreme measures for EGUs based on unrealistic assumptions and calculations. EPA’s EGU datasets are riddled with errors. EPA makes unsupported technology emission reduction feasibility and project-timing suppositions. Aggressive “generation shifting” models rachet down state budgets based on impracticable modeling results, which *have never been applied* to this level in previous transport rules. The proposed Rule also includes new EGU emission reduction concepts that have also *never been applied* in an interstate transport rulemaking. Even EPA’s air quality model and analysis of EGU impacts on downwind receptors is highly questionable.

NRECA implores EPA to rethink this Rule to address these significant shortcomings. We ask EPA to revisit its technical analysis, models, and datasets and make corrections. EPA should provide states with adequate guidance and corrected datasets to address their good neighbor obligations. After issuance of this information, EPA should provide states with a reasonable deadline to submit, or resubmit, their good neighbor state SIPs. This is the process Congress envisioned. It should be followed.

NRECA urges EPA to carefully review the technical flaws commenters have found. With this limited comment period, NRECA has not had sufficient time to review all datasets, assumptions, and technical support for the Rule. We ask for more time for review – at least an additional 60 days from the end of this comment period. In addition, given the number of errors NRECA and others have already found, EPA should re-evaluate its modeling efforts, databases, and technical assumptions and, at the very least, issue a supplemental proposal and provide an opportunity for review and comment on the revised datasets and technical information. Finally, as detailed in our comments that follow, should EPA decide to proceed with a final Rule without the additional analyses that we recommend, EPA should incorporate our suggestions enumerated in Section II to make the proposed Rule technically viable.

Lastly, it is imperative that EPA coordinate with FERC, NERC, and regional entities including Regional Transmission Organizations (RTOs) and Independent System Operators (ISOs) to ensure that this FIP in the final version does not jeopardize a reliable grid and affordable electricity for the health, safety, and security of all Americans.

I. Introduction: NRECA and the Electric Cooperative Profile.

The NRECA appreciates the opportunity to comment on the Proposed FIP.[2] NRECA is the national service organization for America's Electric Cooperatives. The nation's member-owned, not-for-profit electric cooperatives constitute a unique sector of the electric utility industry. providing reliable, affordable, and responsible electricity remains the shared commitment of NRECA's members. For over 80 years, electric cooperatives have responded to the needs of their communities and adapted to changes in federal policy in meeting that commitment. Policymakers must continue to balance realism with aspiration, recognizing that any energy transition will require additional time and technology and must be inclusive of all energy sources to maintain the reliability and affordability that is the cornerstone of American energy security.

The nation's electric grid reliability depends on reliable sources of base load and intermediate load generation. Renewable energy cannot fulfill this need. This fact, combined with the increasing electrification of other sectors of the economy, which is anticipated to require

[2] 87 Fed. Reg. 20036 (April 6. 2022).

a three-fold expansion of the transmission grid and up to 170% more electricity supply by 2050, according to the National Academies of Sciences,[3] will place more demands on the electric grid and measures to enhance grid reliability. We are concerned that if implemented the Proposed FIP would pose significant reliability concerns. In addition, due to their size, history, and structure, rural electric cooperatives and their consumer members would face a significant and unreasonable set of challenges if forced to comply with the Proposed FIP. These comments discuss those challenges and explain why they, along with the legal and technical flaws inherent in the Proposed Rule, justify major changes in the final rule.

NRECA represents the interests of the nation's nearly 900 rural electric utilities. Our members are responsible for keeping the lights on for more than 42 million people across 48 states and 56% of the nation's landmass. Electric cooperatives power communities and empower their residents to improve their quality of life. Affordable electricity is the lifeblood of America's economy. For over 80 years electric cooperatives have proudly shouldered the responsibility of bringing electricity to rural parts of this country. Because of their critical role in providing affordable, reliable, and universally accessible electric service, electric cooperatives are vital to the economic health of the communities they serve.

America's electric cooperatives serve all or parts of 83% of the nation's counties and 13% of the nation's electric customers, while accounting for approximately 12% of all electricity sold in the United States. NRECA's member cooperatives include 63 generation and transmission (G&T) cooperatives and 832 distribution cooperatives and other rural utilities. The G&Ts are owned by the distribution cooperatives they serve. The G&Ts generate and transmit power to nearly 80% of the distribution cooperatives, which in turn provide power directly to the end-of-the-line consumer-members. Remaining distribution cooperatives receive power directly from other generation sources within the electric utility sector. NRECA members account for about 5% of national generation. On net, they generate approximately 40% of the electric energy they sell annually and purchase the balance from non-NRECA members. All electric cooperatives are incorporated as private entities in the states in which they reside. All but three of NRECA's member cooperatives are "small entities" under the Regulatory Flexibility Act, 5

[3] National Academies of Sciences, Engineering, and Medicine. 2021. *Accelerating Decarbonization of the U.S. Energy System.* Washington, DC: The National Academies Press. https://doi.org/10.17226/25932.

U.S.C. §§ 601-12, as amended by the Small Business Regulatory Enforcement Fairness Act. Importantly, distribution and G&T cooperatives share responsibility for serving their members by providing safe, reliable, and affordable electric service.

A. The FIP Proposal Poses Unique Challenges for Cooperative Generation.

Electric cooperatives strive to offer their consumer-members an array of distributed energy resources including solar, energy efficiency, and energy storage commensurate with the interests of their local consumers and communities. Especially over the past decade, many G&Ts have added significant amounts of renewable electric generating resources, along with natural gas, to their generation portfolios. Nevertheless, due to historical factors, steam-electric, coal-fired generation remains the cooperatives' principal means of generating electricity.

For the cooperatives, the need for significant coal-fired generation arose out of necessity, not choice. In the mid 1970s, many existing non-cooperative generation sources could not or would not continue providing affordable and reliable electric generation to the cooperatives. Commensurate with the significant need for cooperative self-generation, the federal government passed the 1978 Powerplant and Industrial Fuel Use Act, 42 U.S.C. § 8301 et seq., which pushed the cooperative generators — the G&Ts — to build significant new baseload generation. That Act *mandated* that all such new generation be "coal capable," so as to preserve natural gas supplies for nonelectric and nonindustrial purposes. The coal capability requirement meant the new generating units bore significantly higher capital costs per megawatt of capacity than units constructed before Congress instituted the requirement. To produce electricity at competitive prices, therefore, the new units had to use coal, which was less expensive than natural gas.[4] The Fuel Use Act was repealed in 1987, but about two-thirds of today's cooperative coal-fired generation was built under the Act's "coal capable" mandate. Given the investments in coal capable generation mandated by the federal government, coal-fired electric generation remains the dominant source of electric generation for G&T cooperatives, comprising approximately 50% of self-generation in 2020, compared to a nationwide average of 27% in that year. That is a major reason why this Proposed FIP would effectively force many cooperatively owned coal-

[4] Many of these units today cannot use natural gas as a primary fuel and provide competitively priced electricity. Coal to gas converted units typically serve short term purposes or provide non-baseload generation and are only available where adequate gas supply is available at the site.

fired units, and other units of which cooperatives must rely on for significant power, to shut down. Thus, if implemented this proposal, would disproportionately harm electric cooperatives, and their consumer-members, relative to the other utility sectors.

B. Cooperative and Consumer Characteristics Present Additional Challenges for Proposed FIP Compliance.

Rural electric cooperatives serve large expanses of the country that are primarily residential and typically sparsely populated. Those characteristics make it comparatively more expensive for rural electric cooperatives to operate than other utility sectors, which traditionally serve more compact, industrialized, and densely populated areas. This is also why other types of utilities have typically shied away from serving rural areas, thus necessitating the advent of member-owned electric cooperatives. Using data from the United States Energy Information Administration (EIA) and other sources, NRECA estimates that rural electric cooperatives serve an average of 8 consumers per mile of transmission line and collect annual revenue of approximately $19,000 per mile of line. In other utility sectors, the averages are 32 customers and $79,000 in annual revenue per mile of line.[5] Due to those geographically driven differences, 63% of rural electric cooperative members pay higher residential electric rates than do the customers of neighboring electric utilities. Higher rates impede the economic recovery of rural communities and can even challenge their viability. That makes it especially important for electric cooperatives to keep their electric rates affordable and avoid the sorts of unnecessary rate increases the Proposed FIP portends.

Low population density affects not only the cost of providing electricity, but also the demand for it. In this respect, rural Americans are uniquely vulnerable to rising electricity costs. For instance, in America's rural expanses, people generally do not live in closely confined houses or in apartments, but in detached, single-unit homes that endure significant exposure to the elements. NRECA estimates that more than 14% of cooperative consumers live in manufactured housing, which is often energy inefficient. The national figure, by comparison, is

[5] Information taken from U.S. Department of Energy, Energy Information Administration EIA Form 861; Platts UDI Directory of Electric Power Producers and Distributors, 2017.

6%.[6] For those reasons, among others, the average household served by electric cooperatives uses 1,115 kWh of electricity each month, significantly higher than the 820-kWh monthly average for households served by investor-owned utilities (IOUs) or the 881-kWh monthly average for households served by municipal-owned utilities (MOUs).[7]

C. Cooperatives serve a disproportionate amount of the nation's economically disadvantaged population.

Many cooperative consumers are among those least able to afford higher electricity rates. In 2019, the average (mean) household income for electric cooperative consumers was 11% below the national average. That is unsurprising, given that electric cooperatives serve 92% of persistent poverty counties (364 out of 395) in the United States.[8] Compounding this problem is the fact that many of these economically disadvantaged member-consumers live in areas with harsh winters and without access to natural gas. Most other heating alternatives, like propane and heating oil, are relatively expensive. Many cooperative member-consumers thus depend on cooperative-generated electricity for warmth during the coldest months of the year. Especially because they lack viable, affordable heating alternatives, it is vitally important to these households that electric rates remain reasonable and that electric supplies remain reliable.

More generally, the electricity supplied by rural cooperatives is vital to rural economies and an essential element of modern residential, rural life. Developing rural parts of the country requires access to affordable and reliable electric power. Factors that increase the cost of producing that electricity, or that threaten its availability, thus pose serious threats to maintenance and growth in large segments of rural America.

To summarize, it is the special province of rural electric cooperatives to serve areas: (1) where it is especially costly to supply electricity; and (2) where, on a geographic basis the aggregate demand for electricity is comparatively low; but (3) where the average resident needs

[6] The percentage of mobile homes as a proportion of housing stock is 14.4% in cooperative territories. The national average is 6.1%. U.S. Census data with calculations provided by EASY Analytic Software, Inc.

[7] This value comes from 2020 weighted average data from EIA Form 861; of course, there is wide variation geographically due to different weather patterns and availability of heating alternatives.

[8] Data from the U.S. Treasury's Community Development Financial Institutions Fund (the CDFI Fund), based on U.S. Census data.

and consumes more electricity than residents elsewhere; and (4) where many of the nation's most economically disadvantaged citizens live. For decades, rural electric cooperatives have met those challenges head-on, with remarkable success. Today, cooperatives continue to play a vital role in life and development in rural communities across the country, despite the obstacles they face in keeping rates reasonable and electricity supply reliable.

D. All Cooperative Financing Costs for Capital Projects Must be Borne Directly by the Cooperative Consumer.

Electric cooperatives are not-for-profit entities; they have no investor equity shareholders who can bear the costs of stranded generation assets or investment in new or alternative generation resources. Consequently, electric cooperatives must ultimately pass along capital costs directly to their consumer-members through increased electric rates. Given that electric cooperatives serve areas with low population density, these costs are borne across a base of fewer consumers and by families that already spend more of their limited incomes on electricity than do comparable MOU or IOU customers. That is yet another reason why cooperatives' members are disproportionately affected by the sorts of rate increases to which the Proposed Rule would give rise.

Given that the G&T cooperatives maintain only marginal cash reserves for unforeseen events and anticipated operating expenses, financing for many capital projects necessarily require reliance on debt investors such as the United States Department of Agriculture's Rural Utilities Service (RUS), National Rural Utilities Cooperative Finance Corporation (CFC), and CoBank. The costs of borrowing, too, are necessarily passed on to cooperatives' consumer members. Ultimately, then, it is the cooperatives' consumer members who bear the cost of changes required by laws like the Clean Air Act and regulations promulgated under it.

II. Recommendations to make the Proposed FIP technically viable without jeopardizing electric grid reliability.

Notwithstanding our concerns about the questionable legality of the Proposed FIP included in these comments that follow, it is not technically workable as we also note below. *We recommend the following technical changes be incorporated into a supplemental proposal and offered for public comment and ultimately included to make the final rule more feasible.*

- The Proposal Rule's Base Case contains numerous inaccuracies such as unit emission rate errors, unit retirement date errors, unit existing NOx technology assumption errors, unit capacity errors mixing net and gross capacities, and incorrect NOx rate assumptions for Selective Catalytic Reduction (SCR) and non-SCR units sharing a common stack. EPA should correct these and other errors leading to state budget miscalculations in the 25 states based on commenter submissions.

- The proposed daily NOx emission rate cap of 0.14 lbs./mmBtu for units with SCRs is not achievable in many cases where unit startups occur. If a daily rate is retained the final rule should eliminate reasonable startup times from the daily emission limit calculations or set a daily NOx mass limit to account for startup times.

- The SCR installation timeline assumptions and the related emission reductions incorporated into the 2026 allowance budget are not supported by empirical data on past SCR installations. The earliest these SCRs could be installed is for the 2027 ozone season, and in most cases electric cooperatives installations require National Environmental Policy Act (NEPA) review extending installation timelines even further. Additionally, existing infrastructure shortfalls and the diminishment of engineering and construction availability and expertise over the past ten years only increase reasonable estimates of required SCR installation times. Also, EPA significantly underestimates SCR costs, thus the Proposed Rule's selected SCR technology drastically exceeds the cost effectiveness ranges in the proposal negating that SCR technology is a reasonable choice in 2026 and in subsequent years

  In any case, units retiring or converting to natural gas by 2030 or by reasonable thereafter should not be required to install any additional technology beyond optimizing existing installed technologies, the daily NOx limit of .14 lbs./mmBtu should not apply and state budgets should reflect these adjustments beginning in 2026 based on emission limitations associated with existing optimized installed controls.

- The Proposed Rule's "generation shifting" within a state should be excluded. Statewide annual allowance reductions in 2023 and 2024 due to generation shifting are based upon a flawed Base Case. The generation shifting cost metrics do not mimic reality, assume without adequate rational that no transmission constraints occur during high electricity demand ozone season, and fail to consider any possible constraints in energy exchanges between RTOs and ISOs. Also, generation shifting creates additional obstacles for small generation systems, such as many electric cooperatives, as detailed below in our comments. Thus, for all these reasons state allowances budgets should be adjusted without the forced imposition of generation shifting.

- The Proposed Rule's assumptions that low NOx burner (LNB) technology once installed can meet a 0.199 lbs./mmBtu NOx emission limits across the board are incorrect. While the preamble at page 20079 states that the limitation will be applied in 2024, the state budgets apply the limitations in 2023. At any rate, EPA cites only a few data points to conclude broad unit wide installation is feasible by 2023, while 2024 is more feasible as noted in the attached technical report. Regarding the proposed emission limit, the Proposed FIP fails to take into account burner configuration and coal combusted, i.e., whether Bituminous, Subbituminous (Lignite) or Powder River Basin (PRB). The LNB correct emission rates should be as follows:

Coal Rank	Tangential-Fired	Wall-fired
Bituminous	0.30	0.32
Subbituminous (Lignite)	0.20	0.22
PRB	0.15	0.19

State budgets and individual unit allocations in 2023 and in subsequent years should be adjusted accordingly.

- The Proposed Rule's dynamic budgeting methodology presents significant potential allowance short falls if EPA's future projections of baseload and intermediate generation fall short. These concerns cannot be overemphasized considering increased generation needs as the nation continues towards greater economywide electrification combined with the Proposed Rule's 10.5% annual limit on banked allowances. EPA should establish an "allowance reserve account" that would allow a utility to purchase additional allowances at a "fair market price" if a unit's actual heat input exceeds the historical heat input EPA used in determining the state budget for a specific budget year. We note that if EPA guesses correctly as the proposal contemplates the "allowance reserve" would never be needed assuming the above-described changes are made to the proposal. Also, the "allowance bank recalibration" to maintain a limited 10.5% is not needed due to the stringency of the Proposed Rule, but if maintained limit should be raised significantly to at least 20%.

- The final rule should include a "reliability safety valve" to ensure actions necessary to maintain grid reliability or to restore grid reliability are not impeded by transport FIP allowance obligations. Elements should include: (1) a non-exhaustive list of reliability triggering events; (2) an opportunity to request relief from the transport rule's regulatory obligations with a statement of why such relief is necessary; (3) identification of entities or parties who can request relief; (4) a description of the process, including time periods to initiate the process and for expedient action on the request (e.g., grant/deny); (5) identification of remedy alternatives or reliability mitigation measures that may be requested, such as relief from CAA penalties and/or access to a bank of emission allowances available at a reasonable cost; and (6) a process to appeal the initial decision.

III. The Proposed FIP will hobble the ability of cooperatives to deliver consistent, reliable, and affordable power to the energy grid.

A. This Proposed Rule will have far-reaching impacts on the power generation sector due to its technology-forcing inflexible approach.

The Proposed FIP proposes an unprecedented suite of tools using the framework of the Cross-State Air pollution Rule (CSAPR) program to drive down NOx emissions. The result is an unveiled attempt to drive out fossil fuel emissions from EGUs, minimizing coal-fired generation in particular. State allocation budgets are set to plummet by 2026. Even well-controlled coal-fired units with SCRs will be forced to operate at reduced capacity factors due to the scarcity of

NOx allocations. However, EPA goes even farther by introducing new assurance concepts. Dynamic budget setting will further rachet down state budgets. Bank recalibration minimizes the allowances sources can save, while a first-time daily NOx rate ensures higher emitting NOx units cannot run. Ultimately, this patch work of requirements leaves no room for flexibility – forcing technology installations or retirements, if the utility cannot afford the retrofits. Lost is the flexibility of prior CSAPR programs. Rather the Proposed Rule is designed to assure a change in generation mix in the short time frame of four years.

EPA is attempting to eliminate the flexibility of the CSAPR trading program. Reduction of allowances in the program will essentially end the use of trading as a compliance tool and force technology installation. The Proposed Rule is clear in its goal of unit retirements, rather than identifying appropriate controls (neither over nor under-control) to resolve good neighbor obligations. As we discuss *infra*, unit retirements are unnecessary to achieve the goals of CAA Section 110(a)(2)(D)(i)(I). Sources must be given flexibility to choose how to reduce NOx within their systems. This is essential to grid stability and reliability.

B. Diminished Fossil Fuel Generation Capacity on an Aggressive Schedule Promises Grid Instability.

The Proposed FIP threatens available generation capacity in several ways.

<u>Retirement of non-SCR equipped Coal-Fired and Gas/Oil-Fired EGUs</u>

Perhaps the most obvious impact of the Proposed FIP is the forced retirement of an overwhelming 42 GW[9] of capacity from 79 EGUs within a short window. Of that capacity, 4,868 MW (16 units) belong to electric cooperatives. The lost capacity spans state lines and RTOs.

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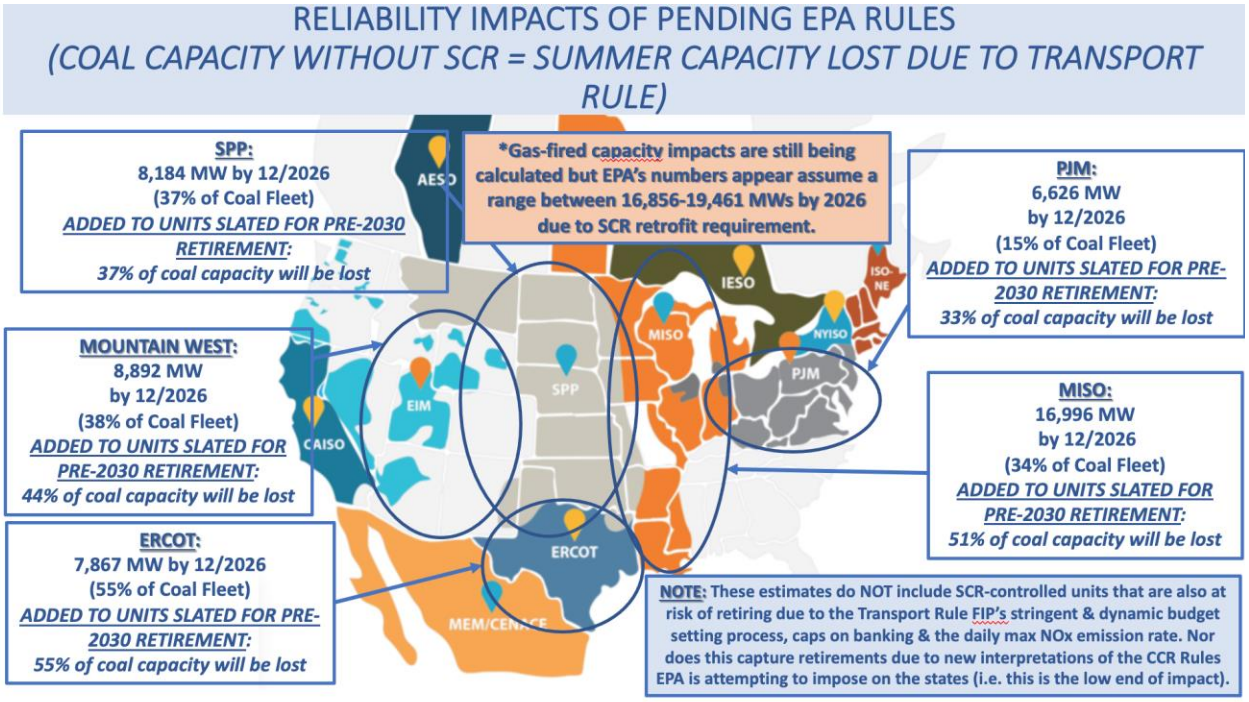
[9] Our analysis of total non-SCR equipped units subject to retrofits is 42 GW as compared to 48.5 GW represented in graphic below. The difference could be attributed to retirements outside the 25 state proposed transport area and announced unit retirements unrelated to the Proposed FIP.



**This graphic uses 2021 data from EIA Form 860 and the EPA NEEDS Summer 2021 reference case. *See* https://www.eia.gov/electricity/data/eia860/ and https://www.epa.gov/power-sector-modeling/results-using-epas-power-sector-modeling-platform-v6-summer-2021-reference

The Proposed Rule does not expressly require these retirements. Rather, through the agency's policymaking approach, it effectively accomplishes this objective. Coal-fired units with capacities of 100 MW or greater must install SCR technology by 2026 because they will not have adequate NOx allocations during the ozone season to continue running. Similarly, gas-fired and oil-fired EGUs greater than 100 MW that emit more than 150 tons of NOx per year are under the same technology installation directive. As discussed in more detail *infra*, installation of SCR technology on smaller emitting units is cost prohibitive. Even if utilities chose to undertake these post-combustion retrofits, the Proposed FIP does not provide adequate time to complete the projects. It is certain this capacity will not be on-line during ozone season 2026 if the Proposed FIP is finalized as proposed. Further, if non-SCR units cannot run from May through September – five months out of the year – the overhead required to run the units for just seven months in the non-ozone season will not justify continued operation.

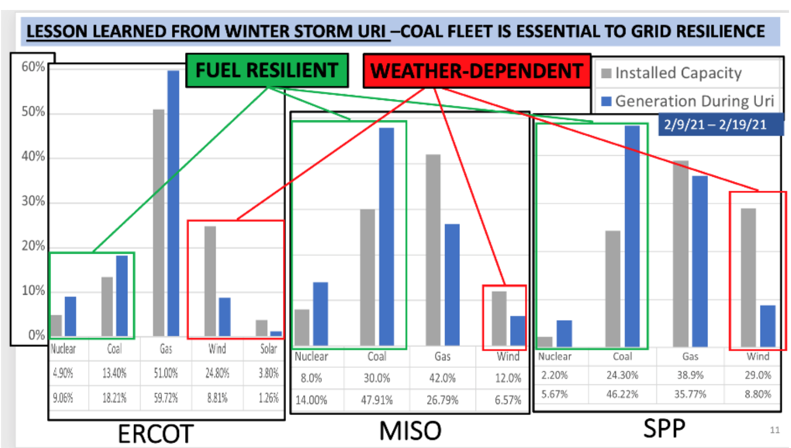
Reduced Capacity Factors for Well-Controlled Coal-Fired Generation

A less obvious effect of the Proposed FIP is a product of its methodology and assumptions. The Proposed FIP locks in unit capacity factors, based on heat input data from

Summer 2021. NOx allocations in state budgets will never exceed the capacity from that key year. EPA then applies dynamic budgeting, which will force capacity factors downward based on future heat inputs – knowing they cannot ever exceed 2021 levels due to the lack of available allowances. For these reasons, existing coal-fired generation cannot make up the non-SCR EGU shortfall caused by the Proposed FIP. It is entirely unclear how the shortfall in generation will be covered.

C. Crippling Baseload Resources further threatens electric reliability.

The Proposed FIP targets fossil generation, which has historically delivered dependable electricity. The Proposed Rule aims to push fossil generation – particularly coal-fired EGUs – offline. The result will impact reliability of the grid, especially given the documented increases in extreme weather events. Hotter summer temperatures, hurricanes, and drought conditions place a strain on reliability. In fact, the Midcontinent Independent System Operator, Inc. (MISO) has projected firm resources will be insufficient to meet demands of this summer 2022.[10] Emergency resources must be deployed to make up the gap during peak demand conditions. The Electric Reliability Council of Texas (ERCOT) has seen a similar impact. For example, on May 13, 2022, extreme temperatures caused 2,900 MW of capacity to trip offline.[11] Unseasonably hot weather drives high demand. These situations do not even account for the reduced available capacity envisioned by the Proposed FIP.



Significantly, the Proposed Rule will reduce capacity from key resources that can respond during extreme weather events. As an example, we can chart the role of fossil fuel generation in the context of Winter Storm Uri that knocked out power in Texas,

[10] *See* MISO Season Demand Assessment for Summer 2022 at https://cdn.misoenergy.org/20220428%20Summer%20Readiness%20Workshop624245.pdf (*visited June 4, 2022*).
[11] *See* https://www.ercot.com/news/release?id=8b772e9e-51d0-4c3c-e653-1e5079f28e89 (*visited June 4, 2022*).

causing devastating effects and deaths. Fuel-resilient resources (coal/nuclear/natural gas) can operate when called-upon, even in adverse conditions. In contrast, intermittent renewable resources (wind/solar) are weather dependent (i.e., electricity is generated only when the wind is blowing and the sun is shining). Pushing fuel-resilient resources off the grid leaves Americans exposed during extreme weather events. These health and safety impacts must be considered, which EPA has not covered in the Proposed FIP.[12]

Indeed, just last week the PJM Interconnection, LLC (PJM) RTO, required outages in Ohio to protect the power grid. The maximum load emergency that was called by PJM on June 14. According to PJM, a transmission disturbance in the American Electric Power Company (AEP) service area in Ohio resulted in multiple 138kv lines going out of service, creating overloads on other transmission lines. PJM then directed AEP to interrupt electricity services in limited areas to relieve and prevent additional overloads. The preliminary cause of the outages were recent storms combined with high temperatures.[13]

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[12] Extreme drought across much of Texas can produce weather conditions that are favorable to prolonged, wide-area heat events and extreme peak electricity demand. *See* NERC, 2022 Summer Reliability Assessment, May 2022 (NERC 2022 Reliability Report) at 4 found at https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2022.pdf (*visited June 5, 2022*). The above figure can be found in this report.

[13] *See* %%dynamic_content_247%%AEP Transmission Disturbance (pjm.com); https://puco.ohio.gov/news/june2022-outages (*visited June 20, 2022*).

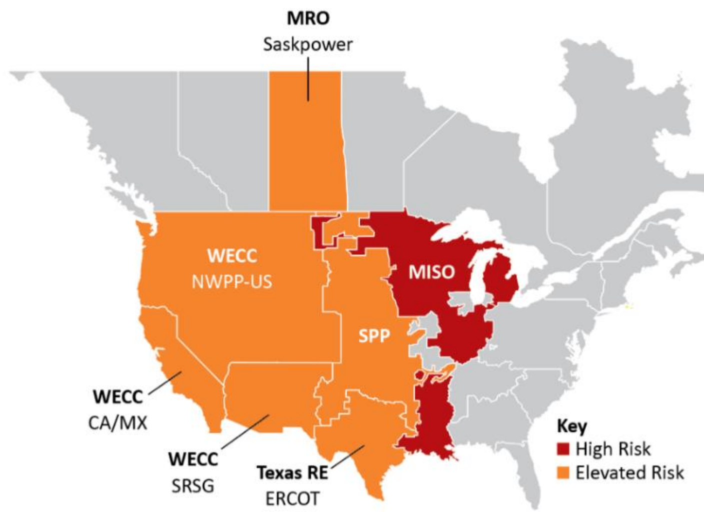

Figure 1: Summer Reliability Risk Area Summary

Seasonal Risk Assessment Summary	
High	Potential for insufficient operating reserves in normal peak conditions
Elevated	Potential for insufficient operating reserves in above-normal conditions
Low	Sufficient operating reserves expected

Separately, NERC identified key regions of the United States that may see a capacity shortfall and cited concerns such as grid security, solar photovoltaic (PV) tripping, supply chain concerns, and stalled transmission projects. NERC projects a high risk of energy emergencies during peak summer conditions for certain areas such as in MISO and Southwest Power pool (SPP).

The NERC Summer Reliability Assessment 2022 raised several reliability issues in addition to the reliability risks caused by extreme drought conditions, including the following:

- Supply chain issues: NERC reports that generation and transmission projects are being impacted as a result of "product unavailability, shipping delays and labor shortages."[14] For generation projects that are included in summer resource projections, and transmission projects that are needed to manage congestion and maintain stability of the Bulk Power System, these delays could result in capacity deficiencies or energy shortfalls.
- Cyber security threats: NERC reports that "amid heightened geopolitical tensions in addition to ongoing cyber risks", the electricity sector faces cyber security threats from Russian attackers.[15]
- Unexpected tripping of PV resources during grid disturbances: During grid disturbances, there have been widespread solar PV losses in the Texas Interconnection and the California area. The widespread solar PV losses were "coupled with the loss of synchronous generation, unintended interactions with remedial action schemes, and some tripping of distributed energy resources."[16]

NERC also raised the possibility of above-normal wildfire risk beginning in June in the South Central U.S. states and Northern California, with a potential for negative impacts on the interconnected transmission system and solar PV resources, at the same time as increased system

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[14] *Id.* at 5.
[15] *Id.*
[16] *Id.* at 5-6.

demand.[17] While the NERC Assessment is for the 2022 summer and the Proposed FIP will be implemented in 2023, implementation of the Proposed FIP would come during a time when NERC has already warned of potential reliability risks. Moreover, the ozone season next year (May to September) will coincide with another summer period. The Proposed FIP does not take into account the combined impact of existing reliability concerns with the additional reliability impacts of at worst, significant unit retirements as discussed below and at least, potential outages for installation of SCRs and Selective Non-Catalytic Reduction (SNCR) units. Failing to account for dire consequences of the Proposed Rule further underscores how EPA is operating far beyond the boundaries of its authority.

D. The Proposed Rule disregards the requirements of regional reliability entities that assure grid reliability.

The timeline of the Proposed FIP, with a trading program beginning in 2023, is not sufficient for generation owners, states and (where applicable) regional reliability entities such as RTOs/ISOs to coordinate compliance and consider mitigated reliability impacts. The baseline changes depend on heat input, which complicates implementation and compliance. The Proposed FIP poses additional unaccounted-for reliability concerns for EGUs that might hope to take a proactive approach by installing new SCR and/or SNCR controls, as well to the extent the Proposed FIP will result in retirements not yet announced.

First and foremost, the Proposed FIP must include a reliability safety valve. This is a mechanism that is critical in order to ensure continued reliability of the power sector, whereby an entity or entities can seek a waiver from the FIP if they demonstrate significant, identified threats to reliability that cannot be avoided or reasonably mitigated. A safety valve would not alter or remedy the fundamentally flawed approach or assumptions in the Proposed FIP. However, it would allow for a reassessment and relief, for changes in the grid that are unforeseeable today. Any safety valve should include at least the following:

1. <u>Potential triggering events</u>: A non-exhaustive identification of potential triggering events.

2. <u>Requested relief and remedial actions</u>: Clarity regarding the (i) relief that can be granted (e.g., complete relief from implementation for a determined period of time; access to a "bank" of emissions allowances available at a fee; relief from penalties; other reliability-

[17] *Id.* at 6.

based mitigation measures); and (ii) remedial actions taken to remedy the circumstances necessitating the relief granted.

3. Process for requesting relief: The process for seeking use of the reliability safety valve, including who can submit a request, contents of a request; which entity or entities will decide the request, time periods for the process, and any opportunity for "appeal" or further review of a decision to grant or deny reliability safety valve remedies.

Second, it is imperative that the timeframe in the Proposed FIP provides for notices and scheduling of regional reliability entities such as RTOs and ISOs. In addition to the long lead time for installation of SCRs/SNCRs discussed in Section VIII, which is exacerbated for cooperative utilities, the reliability-based requirements in organized regions like RTOs and ISOs will make it infeasible for EGUs to simply and unilaterally opt for further NO_x emissions controls technologies. As an example, in order to preserve reliability and sufficient generation resources, PJM (like other RTOs and ISOs) has specific rules for generation outage scheduling.[18] For planned outages that are either a full plant outage or a reduction in plant capability, PJM requires Generation Owners to submit notice at least 30 days prior to the outage and the outage must be outside of the peak period of week 24 through week 36 of each year. This peak period of June through September coincides with the ozone season. PJM then will approve, suggest alternate dates or deny the outage request based on Generator Outage Reserve Margins. PJM analyzes the reliability effect of a generation outage in each zone as well as the PJM region overall. Therefore, Generation Owners' ability to take an outage for SCR/SNCR installation is not certain and is subject to denial if, for example, there would be insufficient generation remaining online from a reliability perspective. While PJM does permit maintenance outages with less notice (3 days), those are generally limited to nine days in duration between major "overhauls," also subject to denial by PJM, and subject to recall for reliability reasons with 72 hour notice. Such short-term maintenance outages simply will not accommodate installation of (1) new SCRs, which EPA optimistically estimates could take as little as 21 months at an individual plant and 36 months at a single plant with multiple boilers,[19] or even (2) state-of-the-

[18] The PJM Generation Outage scheduling rules are contained in PJM Manual 10, available at m10.ashx (pjm.com). A summary of the rules is available in the presentation from May 2022 at 20220310-item-11-transmission-outage-scheduling-process.ashx (pjm.com).

[19] 87 Fed. Reg. at 20080.

art NOx combustion controls under EPA's perhaps unrealistic estimate that such installations would take two to three weeks.[20]

To the extent the Proposed FIP will result in unanticipated generation retirements, those retirements are also subject to RTO and ISO rules that are necessary in order to maintain reliability. For example, MISO requires at least 26 weeks advance confidential notice for a generation retirement so that MISO can conduct reliability impact studies.[21] While EPA has not considered the potential impacts on reliability that will result from EGUs that opt to retire because of the proposed FIP, MISO is mindful and concerned. MISO has recently initiated a process to reconsider its generation retirement process because, in part and according to MISO, "among other factors, EPA regulations are also rushing generation to retirement."[22] MISO specifically cited the Proposed FIP as one of two EPA regulations that are factors in generation deciding to retire, and MISO is considering a proposal to extend its advance notice from 26 weeks to 1 year, in order to afford MISO time to conduct more in-depth studies.[23] Even with a 26-week advance notice, EGUs will be constrained in their ability to make prudent decisions regarding compliance with the Proposed FIP. A longer advance notice period for generator deactivations will only further threaten the feasibility of the Proposed FIP in maintaining reliability in the wake of generation retirements.

Third, missing from the Proposed FIP is discussion of how EPA will coordinate with RTOs/ISOs, agencies like FERC and critical reliability organizations like NERC, as well as perhaps others (state entities) to monitor implementation and compliance. In the past, including for its proposed Clean Power Plan (CPP) and other initiatives, EPA at least made efforts at coordination in order to address reliability impacts of significant rules.[24] For the CPP, EPA coordinated with the Department of Energy (DOE) and FERC in order to "help ensure continued reliable electricity generation and transmission during the implementation of the Clean Power Plan."[25] Those efforts included EPA consulting with DOE and FERC staff in the development of

[20] 87 Fed. Reg. at 20079.
[21] PJM requires at least 90 days advance notice for generator deactivations.
[22] MISO Planning Advisory Committee meeting, April 27, 2022 at 3, available at PowerPoint Presentation (misoenergy.org).
[23] MISO Planning Advisory Committee meeting presentation, June 7, 2022, available at PowerPoint Presentation (misoenergy.org)
[24] *See* EPA-DOE-FERC Coordination on Implementation of Clean Power Plan, August 3, 2015, available at CPP-EPA-DOE-FERC | Federal Energy Regulatory Commission.
[25] *Id.*

its rules, as well as continued coordination in order to ensure compliance with the CPP "in a manner that is fully compatible with the power sector's ability to maintain electric reliability."[26] Moreover, the agencies had a plan for outreach with stakeholders, including (1) utility trade associations and generation owners with affected fleets; (2) organizations of state agencies; (3) RTOs, ISOs and planning authorities; and (4) NERC. There is no such coordination evident in the Proposed FIP, and such coordination is a minimum required component of any FIP. Even if EPA has or is coordinating with these stakeholders regarding the Proposed FIP, EPA should adopt a more formal, publicized process for coordination to at least ensure the Proposed FIP does not have adverse impacts on reliability. NRECA also urges EPA to include these entities as well as other stakeholders in developing a reliability safety valve.

IV. EPA lacks the authority to issue a rule that will entirely transform the energy sector.

Congress granted states and EPA authority to address good neighbor obligations in Section 110 of the CAA. There are limits to this authority. It is impossible to imagine that Congress intended EPA to force the shutdown of 42 gigawatts of generation during the ozone season and likely permanently. Nor is it possible to envision Congress intended EPA to dictate generation dispatch indefinitely through the state budget process. Congress did not grant EPA unfettered authority.

A. Major Questions Doctrine forbids the grant of unlimited authority over the energy sector without clear authorization from Congress.

The federal government's powers are not general but are limited and divided. *McCulloch v. Maryland*, 17 U.S. 316, 405 (1819). To regulate an area, the federal government must properly invoke a constitutionally enumerated source of authority. It must also act consistently with the Constitution's separation of powers. In articulating this obligation, the Supreme Court has established a firm rule: "We expect Congress to speak clearly" if it wishes to grant an executive agency authority over decisions "of vast economic and political significance." *Util. Air Regul. Grp. v. EPA*, 573 U.S. 302, 324 (2014) ("*UARG*"); *see also Alabama Assn. of Realtors v.*

[26] *Id.*

Department of Health and Human Servs., 141 S.Ct. 2320 (2021) (Kavanaugh, J., concurring). Where Congress does not clearly express authority, an agency may not regulate such significant matters. This rule is known as the Major Questions Doctrine.

The Proposed FIP provides for ozone season NOx reductions from EGUs and industrial stationary sources (non-EGUs), EGU unit technology requirements, dynamic budget-setting, daily emission rates for coal-fired EGUs 100 MW or greater, and unit-specific secondary emissions limits, which would collectively result in the wholesale reordering of the U.S. power sector and impact the ability of 332 million Americans to receive reliable, cost-affordable electricity. The Major Questions Doctrine requires Congress make a clear delegation if it intends to give EPA such economy transforming authority. However, neither Section 110 nor anything else in the CAA provides a statement from Congress that it intended EPA to take this power on. Rather, the CAA falls short of a congressional authorization to issue a rule with such sweeping impacts. Given the text of the CAA, the Major Questions Doctrine prohibits EPA from implementing the Proposed FIP.

B. Major Questions Are Poor Candidates for Agency Decision-Making.

When determining whether Congress delegated powers to an agency, it is important to consider the "nature of the question." *Brown & Williamson*, 529 U.S. 120, 159 (2000). When the nature of the question is routine or where a statute is ambiguous, deference is given to an agency to fill in the statutory gaps. *Id.* However, Major Questions are poor candidates for agency decision-making. They "should be [answered] by the national legislature, the branch best equipped by its structure and constituency" to respond to competing interests and priorities. *United States v. District of Columbia*, 669 F.2d 738, 744 (D.C. Cir. 1981). Major Questions often involve matters extending beyond a single agency's expertise. Therefore, Congress must "speak clearly" to grant an agency authority over a Major Question. *UARG*, 573 U.S. at 324.

The Major Questions Doctrine rests on "two overlapping and reinforcing presumptions." *U.S. Telecom Ass'n v. FCC*, 855 F.3d 381, 419 (D.C. Cir. 2017) (Kavanaugh, J., dissenting from denial of rehearing en banc). The first presumption is that Congress "intends to make major policy decisions itself." *Id.* Second, in making those decisions, Congress should default against delegating "major lawmaking authority." *Id.*

C. The Proposed FIP poses a Major Question.

The Proposed FIP has all the characteristics of a major question. When determining whether a question is "major," the Supreme Court has considered the following factors:[27] (1) the amount of money involved for regulated and affected parties and the overall impact on the economy, (2) the number of people affected, and (3) the degree of congressional and public attention to the issue. *U.S. Telecom Ass'n*, 855 F.3d at 422-23 (Kavanaugh, J., dissenting from denial of rehearing en banc); *See UARG*, 134 S.Ct. at 2443-44 (regulation would impose massive compliance costs on millions of previously unregulated emitters); *Gonzales v. Oregon*, 546 U.S. at 267, 126 S.Ct. 904 (physician-assisted suicide is an important issue subject to "earnest and profound debate across the country"); *Brown & Williamson*, 529 U.S. at 126-27, 133, 143-61, 120 S.Ct. 1291 (Food and Drug Administration's asserted authority would give it expansive power over tobacco industry, which was previously unregulated under the relevant statute); *MCI Telecommunications Corp. v. Am. Telephone & Telegraph Co.*, 512 U.S. 218, 230-231, 114 S.Ct. 2223 (rate-filing requirements are "utterly central" and of "enormous importance" to the statutory scheme).

In this case, each of the Court's factors are present. First, the breadth of financial impact of the Proposed FIP on regulated parties and the overall impact on the economy is hard to overstate. Implementation of the Proposed FIP is deemed an "economically significant regulatory action" as defined by the Office of Budget and Management (OMB). Economically significant actions impact the American economy more than $100 million annually or will cause a material adverse effect on the economy.[28] The exact cost of the Proposed FIP is in dispute, as EPA's estimates are understated.[29] Regardless, it is not in dispute that financial repercussions on

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[27] There is no bright-line test in Supreme Court jurisprudence.

[28] OMB states: "A regulatory action is determined to be "economically significant" if OIRA determines that it is likely to have an annual effect on the economy of $100 million or more or adversely affect in a material way the economy, a sector of the economy, productivity, competition, jobs, the environment, public health or safety, or State, local, or tribal governments or communities. For all "economically significant" regulations, the Executive Order directs agencies to provide (among other things) a more detailed assessment of the likely benefits and costs of the regulatory action, including a quantification of those effects, as well as a similar analysis of potentially effective and reasonably feasible alternatives." *See* *https://www.reginfo.gov/public/jsp/Utilities/faq.myjsp* *(visited on June 4, 2022)*.

[29] EPA's cost estimates are found in the Regulatory Impact Analysis for Proposed Federal Implementation Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standard, February 2022 (Proposed FIP Regulatory Impact Analysis). As discussed *infra*, at a minimum, technology installation costs are underestimated.

states, the utility sector, end users, small businesses, EGUs and non-EGUs will be momentous. Costs of early retirements, stranded assets, and replacement generation will burden the American economy. SCR technology installation projects alone are projected to cost $24,340 per NOx ton removed, escalating to approximately $50,000 per ton.[30]

The expression of economic costs fails to adequately capture the broader transformative effects of the Proposed FIP on a significant percentage of the American population. Electricity is an "essential" and foundational element of modern life. *Puerto Rico v. Franklin Cal. Tax-Free Tr.*, 136 S. Ct. 1938, 1950 (2016). The electric power industry is a "significant portion of the American economy." In comparison, the Supreme Court considered an attempted overhaul of the tobacco industry to be a major question. *Brown & Williamson*, 529 U.S. at 159. The Proposed FIP will result in substantial modifications to the U.S. energy supply sector and significant grid reliability issues for 84 million Americans.

Finally, these issues are at the center of substantial political and public attention. Congress, in recent years has been and remains heavily engaged in climate change-related issues and continually debates approaches to emissions regulation. As such, it is clear the Proposed FIP presents a Major Question, which may only be answered by Legislative action.

D. Congress did not delegate power to EPA to restructure the Energy Sector.

The Supreme Court has used the Major Questions Doctrine to hold Congress did not grant EPA certain powers it claimed under the CAA. *UARG* considered whether EPA could extend permitting requirements to a vast category of greenhouse gas-emitting sources. 573 U.S. at 315. The Court determined it could not. To determine otherwise, the Court held, would require "an enormous and transformative expansion [of EPA's] regulatory authority without clear congressional authorization." *Id.* at 324. If EPA "lay[s] claim to extravagant statutory power over the national economy," then it must explain why the statute "compel[s]" that interpretation. *Id.*; *see also Whitman v. Am. Trucking Assocs.*, 531 U.S. 457, 468 (2001) (holding EPA could not consider implementation costs when setting national ambient air quality standards without a "clear" "textual commitment" on that score).

[30] Costs of SCR, SNCR, and combustion control projects are discussed in Section IX, *infra*.

In the CAA, Congress did not express a clear statement of the expansive authority presumed by EPA in the Proposed FIP. Likewise, EPA does not explain why the CAA "compels" such an interpretation. CAA section 110(c)(1) requires the Administrator to promulgate a FIP at any time within two years after they: (1) find a state has failed to make a required SIP submission; (2) find a SIP submission incomplete pursuant to CAA section 110(k)(1)(C); or (3) disapprove a SIP submission. Section 301(a)(1) of the CAA gives the Administrator general authority to prescribe regulations necessary to carry out functions under the Act. Pursuant to this section, EPA has authority to clarify applicability of CAA requirements and undertake other rulemaking action to implement CAA requirements.

According to the Proposed FIP, EPA may use Sections 110(c) and 301(a)(1) to employ a federal plan, which would result in the forced change of U.S. energy generation mix in the short time frame of four years, including forced retirements due to SCR installations and severe limitation of capacity due to budget constraints. In doing so, the Proposed FIP alleges EPA need only consider whether States met the statutory deadline of CAA Section 110(a). It is clear; Congress did not grant EPA such authority. For this reason, EPA should withdraw the expansive Proposed FIP. Following the text of the CAA, EPA should allow states the opportunity to resolve their own good neighbor obligations in a state and federal collaborative effort that has been a hallmark of CAA implementation between EPA and the states for decades.

E. **Congress has not delegated EPA authority to regulate the utility markets, nor has Congress given EPA instructions on how to use that power.**

The Proposed FIP grasps powers not delegated to EPA. Like the Major Questions Doctrine, the Nondelegation Doctrine ensures critical choices of economic and societal policy are made by Congress. *Industrial Union Dept. v. American Petroleum Institute*, 448 U.S. 607, 685-86 (1980). The Doctrine requires where Congress delegates authority to an Agency, it must provide the Agency with an "intelligible principle" to guide and limit exercise of the authority. Id. (citing *J. W. Hampton & Co. v. United States*, 276 U.S., at 409, 48 S.Ct., at 352; 72 L.Ed. 624 (1928); *Panama Refining Co. v. Ryan*, 293 U.S., at 430, 55 S.Ct., at 252). Where the Agency seeks to act outside such intelligible principles, the Nondelegation Doctrine restricts such action.

The Proposed FIP presumes EPA was delegated authority to regulate energy utility markets. The Proposed Rule's erroneous interpretation of CAA Section 110(c) allows EPA to unilaterally reshape the American energy sector based on its important — but singular — mission to protect the environment. Such a reading at the least "sail[s] close to the wind with regard to the principle that legislative powers are nondelegable." *Reynolds v. United States*, 565 U.S. 432, 450 (2012) (Scalia, J., dissenting).

When delegating authority to an agency, Congress must provide some guidance, standard, or guardrail within which the agency may act. Delegation is constitutional only within the "specific restrictions" of the statute, which "meaningfully constrain" agency discretion. *Touby v. United States*, 500 U.S. 160, 166-67 (1991). The Constitution bars Congress from giving "literally no guidance" or overly vague standards when conferring agency power. *Whitman v. American Trucking Associations*, 531 U.S. 457, 474 (2001). At a minimum, Congress must provide "an intelligible principle to which [the agency] is directed to conform." *Gundy v. United States*, 139 S. Ct. 2116, 2123 (2019); *see also id*. at 2139-40 (Gorsuch, J., dissenting) (questioning whether even a few "intelligible principles" are enough to save an overbroad delegation of legislative power). Agencies may fill in statutory gaps with "judgments of degree," *Whitman*, 531 U.S. at 475, but they may not set "the criteria against which to measure" their own decisions. *Gundy*, 139 S. Ct. at 2141 (Gorsuch, J., dissenting). Agencies must instead act within the "sufficiently definite and precise" statutory authority set forth by Congress. *Yakus v. United States*, 321 U.S. 414, 426 (1944).

In this case, EPA seeks to exercise authority wholly outside of the intelligible principles to which Congress required it conform. Congress intelligibly articulated the principles of the CAA as follows:

1) to protect and enhance the quality of the Nation's air resources so as to promote the public health and welfare and the productive capacity of its population;
2) to initiate and accelerate a national research and development program to achieve the prevention and control of air pollution;

3) to provide technical and financial assistance to State and local governments in connection with the development and execution of their air pollution prevention and control programs; and
4) to encourage and assist the development and operation of regional air pollution prevention and control programs.

42 U.S.C. § 7401(b). These principles do not include expansive authority over the energy sector, which is presumed by the Proposed FIP. If implemented, the Proposed FIP would result in the wholesale reordering of the U.S. power sector, through forced retirements due to SCR installations and severe limitation of capacity due to budget constraints. The Proposed FIP's restriction of the energy sector is not merely regulatory gap-filling but rather equates to EPA setting "the criteria against which to measure" their own decisions. *See Gundy*, 139 S. Ct. at 2141 (Gorsuch, J., dissenting).

F. The Proposed FIP ignores congressionally granted authority to other agencies to manage energy sector issues at the peril of grid instability.

Not only has EPA not received Congressional authority or instructions to promulgate the expansive Proposed Rule, but EPA has infringed on the statutorily delegated space of other agencies and entities. FERC regulates interstate energy policy. FERC has delegated its authority over grid reliability to NERC.

As part of the Energy Policy Act of 2005, Congress gave FERC the responsibility of protecting reliability and cybersecurity of the Bulk-Power System through establishing and enforcing mandatory reliability standards. FERC regulates transmission and the wholesale sale of electricity in interstate commerce. In its Strategic Plan, FERC defined a mission of the agency as ensuring "Reliable, Safe, Secure, and Economically Efficient Energy for Consumers at a Reasonable Cost." To that end, FERC seeks to ensure just and reasonable rates, terms, and conditions. As another part of its mission, FERC is tasked with "facilitating the development of the electric infrastructure needed for the changing resource mix."[31]

[31] See FERC Strategy Plan for Fiscal Years 2022-2026, Mar. 28, 2022, at https://www.ferc.gov/media/ferc-fy22-26-strategic-plan (*visited June 4, 2022)*.

The Proposed Rule provides EPA with the power to significantly impact national electricity and energy markets across state lines,[32] at its sole discretion. Using the CSAPR program, the Proposed FIP will impact energy markets across jurisdictions due to shutdowns, capacity limitations, and uneven cost burdens within Group 3 states and as compared to states in the same regional transmission organization outside of the Proposed FIP. EPA proposes to initially handcuff fossil generation and retain a hand on the markets through continuing changes to NOx budgets and diminishing the banks (dynamic budgeting and bank recalibration). EPA is proposing to have a continued hold over the energy market for years to come.

These actions usurp FERC's jurisdiction and its delegated authority to NERC. Not only is EPA operating outside its purview, but, to our knowledge, EPA did not consult FERC or NERC during development of this Proposed Rule. This is a brazen disregard for agency authority and protocol. EPA should retract the Proposed FIP because it extends beyond its authority.

V. EPA has acted contrary to the Clean Air Act's Good Neighbor framework by failing to provide states with a meaningful opportunity to address their own Good Neighbor obligations.

EPA's rule development track record from 2018 to present is inconsistent with the statutory text and meaning of the CAA. States were never given an opportunity to have a first cut at their good neighbor obligations. Congress did not grant EPA unilateral authority to address good neighbor obligations. "The Clean Air Act regulates air quality through a federal-state collaboration." *Homer City*, 795 F.3d 118, 124 (D.C. Cir. 2015). After EPA identifies National Ambient Air Quality Standards (NAAQS) and determines attainment, states have the first opportunity to prepare plans (SIPs) to provide for "implementation, maintenance, and enforcement" of the NAAQS within three years of its issuance. CAA § 110(a)(1). CAA Section 110 then provides EPA the baton by requiring a FIP if a state does not submit a SIP or the SIP is inadequate. *Homer*, 795 F.3d at 124 (discussing the cooperative framework).

[32] EPA recognizes the "highly coordinated, interconnected systems" and even contemplates generation shifting to non-CSAPR units outside of this rule in its generation shifting model as discussed in Section 8. *See* 87 Fed. Reg. at 20081.

Due to EPA's actions, states never had an opportunity to craft plans to address CAA Section 110(a)(2)(D)(i)(I), contrary to the CAA framework. The history of issuance of guidance and rulemaking activities is revealing. EPA released three guidance documents in 2018 to inform states how to address their good neighbor obligations. It was appropriate for EPA to provide this direction, as states need EPA's modeling analysis and direction to submit a compliant SIP, discharging their statutory obligations.[33] In 2019, 2020, and 2021, EPA did not issue any further guidance. EPA also declined to respond to SIP submittals by states that relied on these 2018 guidance documents, other than as to approving Iowa's SIP in 2020. Naturally, states assumed the last issued guidance documents in 2018 reflected the opinions of EPA on good neighbor obligations.

On February 22, 2022, out of the blue, EPA rejected 19 good neighbor SIPs that relied on 2018 guidance for the 19 states that submitted them.[34] Then EPA signed the Proposed FIP on February 28, 2022. EPA reversed its positions articulated in 2018 Guidance in the Proposed FIP.

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[33] *See* Tsirigotis memo, "Information on Interstate Transport State Implementation Plan Submissions for the 2015 Ozone National Ambient Air Quality Standards Under Clean Air Act Section 110(a)(2)(D)(i)(I)" dated March 27, 2018 (https://www.epa.gov/sites/default/files/2018-03/documents/transport_memo_03_27_18_1.pdf); Tsirigotis memo, "Analysis of Contribution Thresholds for Use in Clean Air Act Section 110(a)(2)(D)(i)(I) Interstate Transport State Implementation Plan Submissions for the 2015 Ozone National Ambient Air Quality Standards" dated August 31, 2018 (EPA Contribution Thresholds 2018 Memo) (https://www.epa.gov/sites/default/files/2018-09/documents/contrib_thresholds_transport_sip_subm_2015_ozone_memo_08_31_18.pdf); Tsirigotis memo, "Considerations for Identifying Maintenance Receptors for Use in Clean Air Act Section 11 0(a)(2)(D)(i)(I) Interstate Transport State Implementation Plan Submissions for the 2015 Ozone National Ambient Air Quality Standards" (https://www.epa.gov/sites/default/files/2018-10/documents/maintenance_receptors_flexibility_memo.pdf).

[34] Air Plan Disapproval; Maryland; Interstate Transport Air Pollution for the 2015 8-Hour Ozone National Ambient Air Quality Standard. 87 Fed. Reg. 9463 (Feb. 22, 2022); Air Plan Disapproval; New York and New Jersey; Interstate Transport Air Pollution for the 2015 8-Hour Ozone National Ambient Air Quality Standard. 87 Fed. Reg. 9484 (Feb. 22, 2022); Air Plan Disapproval; Kentucky; Interstate Transport Air Pollution for the 2015 8-Hour Ozone National Ambient Air Quality Standard. 87 Fed. Reg. 9498 (Feb. 22, 2022); Air Plan Disapproval; West Virginia; Interstate Transport Air Pollution for the 2015 8-Hour Ozone National Ambient Air Quality Standard. 87 Fed. Reg. 9516 (Feb. 22, 2022); Air Plan Disapproval; Missouri; Interstate Transport Air Pollution for the 2015 8-Hour Ozone National Ambient Air Quality Standard. 87 Fed. Reg. 9533 (Feb. 22, 2022); Air Plan Disapproval; Alabama, Mississippi, Tennessee; Interstate Transport Air Pollution for the 2015 8-Hour Ozone National Ambient Air Quality Standard. 87 Fed. Reg. 9545 (Feb. 22, 2022); Air Plan Disapproval; Arkansas, Louisiana, Oklahoma, and Texas; Interstate Transport Air Pollution for the 2015 8-Hour Ozone National Ambient Air Quality Standard. 87 Fed. Reg. 9798 (Feb. 22, 2022); Air Plan Disapproval; Illinois, Indiana, Michigan, Minnesota, Ohio, Wisconsin; Region 5 Interstate Transport Air Pollution for the 2015 8-Hour Ozone National Ambient Air Quality Standard. 87 Fed. Reg. 9838 (Feb. 22, 2022). EPA rejected more good neighbor SIPs after the Proposed FIP was released. *See, e.g.,* 87 FR 31495 (May 24, 2022) (Wyoming SIP); 87 FR 31470 (May 24, 2022) (Utah SIP); 87 FR 31485 (May 24, 2022) (Nevada SIP).

This action is equivalent to sand-bagging states that relied on prior EPA modeling, contribution thresholds (dictating which states must submit SIPs), and overall approach.[35] There was no notice of this reversal of position. As a result, states had no opportunity to respond to EPA's change of policy by submitting or resubmitting revised SIPs or any opportunity for states to respond to EPA's concerns whatsoever.

EPA's actions are inherently unfair. States were not provided meaningful opportunity to fulfill their obligations afforded by the CAA statutory framework. Although EPA can act at any time to issue a FIP within the two years after EPA determines a SIP is inadequate, here, there was no opportunity whatsoever for states to have input into the process. *Homer City*, 572 U.S. 489, 507-08 (2014). Instead, EPA issued guidance in 2018, failed to follow up for over three years, materially reversed its position on good neighbor SIP requirements without notice, rejected 19 of the submitted SIPs (except the Iowa SIP) and signed the Proposed FIP less than a week after the disapprovals. This contradicts the cooperative CAA framework. EPA should have provided notice of its reversal of position in guidance and then provided states a "reasonable deadline" for submission of plan revisions. CAA, Section 110(k)(5).

NRECA asks EPA to thoughtfully consider the comments in this docket concerning modeling, missing data, and flawed assumptions, which are discussed herein. EPA should take time to correct these errors and re-issue corrected models via guidance – effectively updating 2018 Guidance documents. Then states should be given a reasonable deadline to submit or re-submit SIPs to address their good neighbor obligations. Should EPA decline NRECA's suggestion not to finalize the Proposed FIP, our comments identify the following significant concerns with the Proposed Rule's approach, data, assumptions, and methodology, and these concerns are reflected in our recommendations in Section II to make the proposal technically viable.

[35] *See, e.g.*, 87 Fed Reg 20036 at 20073 (rejecting the August 2018 Guidance Memo by stating "EPA notes that it is authorized to exercise discretion in making policy determinations such as the appropriateness of a particular contribution threshold that would otherwise have been exercised by states. Further, as the EPA has explained in several notices proposing transport SIP disapprovals, see, e.g., 87 FR 9498 and 87 FR 9510 (Feb. 22, 2022), its experience since the issuance of the August 2018 memorandum regarding use of alternative thresholds leads the Agency to now believe it may not be appropriate to continue to attempt to recognize alternative contribution thresholds at Step 2, either in the context of SIPs or FIPs.").

VI. EPA's Air Quality Projections of Ozone Concentrations in 2023, 2026, 2032 (CSAPR Step 1 approach and continued in the Proposed Rule) are based on a Flawed Model and Assumptions.

A. Limiting Future Emissions to Levels Commensurate with a Single, Past Ozone Season (2021) is arbitrary and capricious.

Use of a single ozone season base case to "lock in" EGU runtime nationwide is erroneous. EPA uses Summer 2021 EGU inventory for its model Base Case for 2023 and into the future. The model plugs in unit-level heat input data from 2021 for use in state budgets. EPA presumes 2021 heat inputs are appropriate as a representative year of consumer demand. In so doing, the model caps heat inputs for all future years. There are no adjustments in state budgets to account for future generation demands.

Although EPA has deference in its modeling choices, its model must bear a rational relationship to the characteristics of the data to which it is applied. *EME Homer City Generation, L.P. v. EPA*, 795 F.3d 118, 135 (D.C. Cir. 2015) (citing *Appalachian Power Co. v. EPA*, 135 F.3d 791, 802 (D.C. Cir. 1998)). Otherwise, use of the model is arbitrary and capricious. Here, using the Summer 2021 EGU inventory leads to results divorced from the reality of power demands between 2023 through 2032 and for maintenance of attainment beyond.

EPA's model fails to account for future power sector demands. NRECA's CEO testified on this point in March: "The increasing role of electrification will place more demands on the electric grid and generation portfolio, and measures to enhance grid reliability are essential to maximize emission reductions and keep costs affordable."[36] In a recent study by the National Renewable Energy Laboratory (NREL),[37] future electricity demand will increase. Future power sector demands are modeled to grow by 20% and 35% under NREL's medium and high scenarios, respectively, reflecting impacts such as electrification of transportation and building sectors.

[36] J. Matheson Testimony, March 2022.
[37] NREL, Electrification Futures Study: Scenarios of Electric Technology Adoption and Power Consumption for the United States (2018) (NREL 2018 Study).

As demand increases beyond 2021-levels, EGUs must respond and deliver reliable power to the grid. However, if existing EGUs cannot operate above their heat inputs in 2021, they cannot meet the demand. State budgets will handcuff units from meeting greater demands.

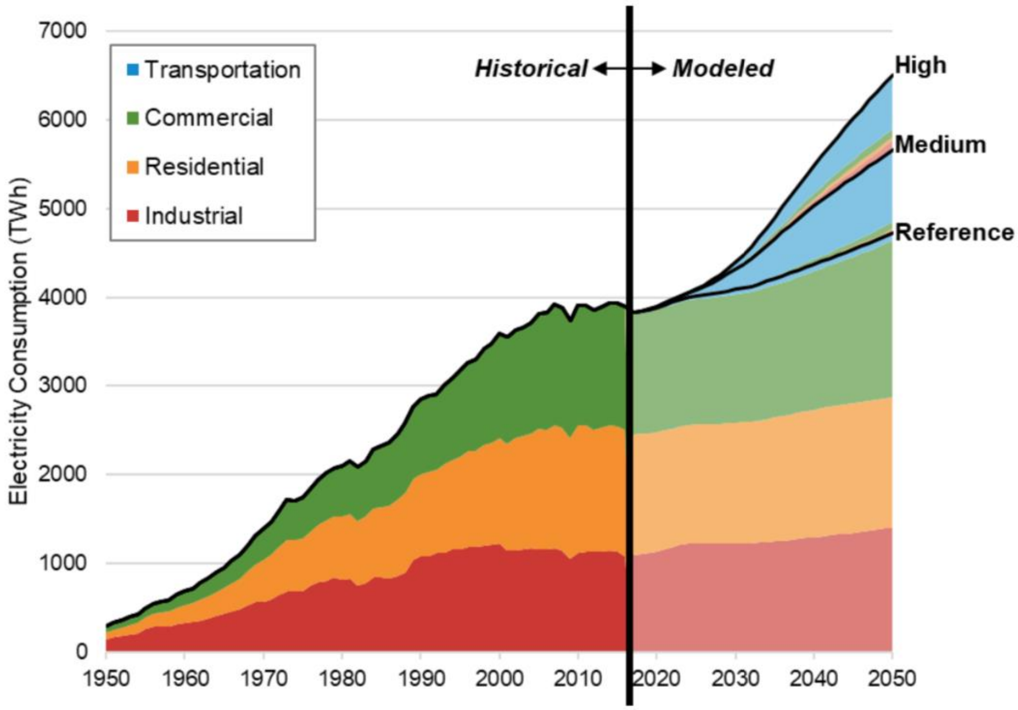

Figure ES-3. Historical and projected annual electricity consumption

Moderate technology advancements are shown. Slight adjustments were made to the modeled industry consumption estimates (for 2017-–2020) to align them with available historical data.

Dynamic budgeting will not correct this problem. If units operate more, increased combustion results in additional NOx emissions. However, units cannot practically emit much above 2021 heat inputs due to scarcity of allocations, state budget size, and resulting assurance features in the Proposed FIP. Dynamic budgeting will only serve to decrease budgets, which will not account for increased demand.

As an example, if a unit runs at a capacity factor of 80% in 2021, the model assumes its NOx tonnage (translating into its Group 3 allocations) based on that runtime number. However, if demand from the RTO is higher in a future year, that unit will not have allocations to cover the additional operation. The utility owner must curtail units due to lack of allocations or determine whether it can afford to purchase allowances, which we project in Section XI.B to be cost prohibitive. The only other option would be to not supply the power needed or build new generation, which may not be sufficient regardless of how much is built. The end result is unworkable and expensive if an existing unit cannot cover the increased demand.

We suggest EPA correct this modeling flaw because it departs from the reality of rapidly changing electrification as sectors depart from combustion of fossil fuels for transportation, heating, appliances, and industrial processes.[38] While EPA is promoting departure from fossil fuel dependence, the Proposed Rule hampers these efforts by not taking the byproduct (future electricity demand) into account. To address this problem in addition to our recommendations in Section II, EPA should consider a base case reliant on the average of three ozone seasons. An average will help to remove the irregularities based on a single ozone season. To account for increased demand for power in the future, EPA should build in a demand growth factor into the budgets beginning in 2026, at the latest.

B. State Budgets are Riddled with Unit-Specific Errors in the Base Case and Erroneous Assumptions for Future Years.

There are other inaccuracies in EPA's 2021 EGU emission inventory in the model. Unlike the unit generation "discrepancies" that the *Homer City* court found passible, the errors in the Proposed FIP base case are numerous. *See Homer City*, 795 F.3d at 135-36. The result is an unreliable model that presents a significant departure from the real EGU emission inventory for 2021 and a strong case that EPA's Proposed FIP overcontrols emissions in its attempt to satisfy good neighbor provisions of the CAA. Prior to release of the Proposed FIP, NRECA identified inaccuracies in the Emission Inventory Platform (2016v2) used by EPA for the Rule. We appreciated the opportunity to informally engage with EPA concerning the common goal of an accurate EGU inventory. However, perhaps due to the complexity and timing of this rulemaking, issues raised earlier were not corrected in this Proposed Rule. We encourage EPA to continue to engage with stakeholders, such as NRECA, consider our constructive feedback, and correct inaccuracies in model inventories used for rulemakings.

All of the errors we were able to discover during this comment period are reflected in the Technical Report commissioned by NRECA, the Midwest Ozone Group and the American

[38] NREL 2018 Study at x-xi.

Public Power Association[39] submitted with these NRECA comments to analyze EPA's technical analysis and methodologies used in the Proposed FIP.[40] However, given the limited time for commenting, other errors may exist in state budgets and otherwise. We urge EPA to make corrections and perform an extensive quality assurance review of all state budget data.

We have identified the following categories of errors in the Base Case:

The Base Case Contains Emission Rate Errors. There are incorrect assumptions as to NOx emission rates for SCR and non-SCR units sharing a common stack. NOx emission rates were not accurate with respect to natural gas conversions.

The Base Case Contains Retirement Date Errors. Some units are assumed to retire earlier than planned. Some units are assumed to be retired in 2023 and have no allocations in the state budgets at all. The result is lower state budgets because the units were removed mistakenly.

The Base Case Assigns the Wrong NOx Technology to Certain Units. Some on-the-books controls are not accurate in the inventory. Units are assumed to have functional SCRs when these units do not. The units are then assigned a lower NOx rate assumption earlier than is achievable.

The Base Case Identifies Incorrect Unit Capacities. The budgets assign net capacities to some units and gross generation to others. EPA relies on the unit capacities to compare against the Proposed Rule's thresholds, such as the threshold for oil/gas SCR retrofits. The unit capacities should follow an accurate and consistent approach.

The Base Case Capacity Factors Cannot be Reproduced and May be in Error. The flawed and inconsistent unit capacities are likely the cause of our inability to reproduce the unit capacity factors EPA devised. We were unable to confirm the 2021 unit capacity factors are accurate based on what is in the rulemaking record.

[39] J. Edward Cichanowicz, James Marchetti, Michael C. Hein, and Shirley Rivera, "Technical Comments on Electric Generating Unit Control Technology Options and Emission Allocations Proposed by the Environmental Protection Agency in Support of the Proposed 2015 Ozone NAAQS Transport Rule" dated June 17, 2022 (the Technical Report).
[40] Technical Report at Section 9.

C. State Budget Assumptions for Future Years (2026 and beyond) are unworkable.

EPA weaves unrealistic and unachievable expectations into the future state budgets. First, EPA assumes technology retrofits can occur in aggressive timeframes that cannot be met. Combustion modifications must occur by 2023 – less than a year from when the Proposed Rule is expected to be finalized. SCR installations are due by 2026 or within 3.5 years. As explained in detail in Section VIII.B, units cannot achieve either project in time.

State budgets reduce ozone season allocations based on emission rates for combustion modifications for coal-fired units. These rates are unattainable by any type of boiler combusting bituminous coal by a large margin. Section VIII.D lays out attainable emission rates by coal type and boiler type.

D. Conclusion and Recommendations.

Base budget case inaccuracies and future budget assumptions must be corrected due to the stringency in allowance allocations and proposed methodology in the Proposed Rule. At present, the base budgets are flawed to the extent there are not passible "discrepancies" that a court would allow. Future budgets are not workable when units are not able to achieve the assumptions in control device installation timing (SCR) or technology rates (combustion technology). For example, if an SCR installation project falls behind, the source loses its generation for that ozone season. While past iterations of CSAPR were not perfect, budgets had more allocations to provide a margin of error. Sources were able to bank allocations without losing them to recalibration, and budgets were not dynamic. Here, there is no room for error. EPA must make these corrections and take more time to ensure budgets are accurate. Otherwise, the diminished budgets will cause reliability concerns if units cannot operate during the ozone season due to lack of allowance availability.

State budgets should be recalculated using achievable assumptions commensurate with appropriate time frames for project completion and technology. The Technical Report recalculates nine state budgets as examples.[41] The corrected budgets rectify unit-specific errors

[41] *See* Technical Report at Table 9-6 (Optimized Baseline numbers should be used).

and apply achievable budget assumptions. NRECA asks EPA to recalculate *all* state budgets consistent with these examples.

VII. The Methodology and Model for Quantifying Contributions from Upwind States to Downwind Receptors is Fatally Flawed (CSAPR Step 2 approach and continued in the Proposed Rule).

A. EPA should use a 1 ppb contribution threshold.

EPA chose the most rigorous upwind contribution threshold option of 1% of the 2015 Ozone NAAQS without justification. In fact, even EPA discussed less stringent options as appropriate for this NAAQS. The contribution threshold defines which states are upwind contributors subject to EGU, non-EGU, or both for the Proposed Rule. Contribution thresholds are also a key variable in the overcontrol analysis – which ensures downwind attainment/maintenance cannot be reached with less stringent requirements. As reflected by EPA's compliance cost estimates, hundreds of millions of dollars are at stake in this decision. It cannot be taken lightly.

In its 2018 Guidance to assist states with good neighbor SIP development, EPA found "a threshold of 1 ppb may be appropriate for states to use to develop SIP revisions addressing the good neighbor provision for the 2015 ozone NAAQS."[42] EPA reasons the 1 ppb threshold is "generally comparable" to the amount of upwind collective contribution captured by a 1 percent threshold (0.70 ppb). The difference is only 77% versus 70% of total upwind contribution.[43] Therefore, EPA advised states the 1 ppb threshold could be used as a basis for good neighbor SIPs. In fact, as discussed in more detail in Section III *supra*, states relied on 1 ppb thresholds in accordance with EPA guidance -- only to get SIP denials in 2022 because EPA changed its position without giving those states any opportunity to respond to this significant policy change in contribution stringency.

EPA addresses the 2018 Guidance in the Proposed FIP but brushes it aside with little discussion. EPA explains it may exercise its judgment in making policy decisions and that 1 ppb

[42] EPA Contribution Thresholds 2018 Memo at 3.
[43] *Id.* at 4.

has the disadvantage of losing roughly 7% of total upwind state contribution.[44] EPA also notes a 1% threshold was used in past CSAPR rulemakings with higher ozone NAAQS standards. EPA points to further analysis in SIP Denials; however, its analysis in support of a 1% threshold is vague and underwhelming. For example, in the recent Wyoming SIP Denial, EPA stated "use of an alternative threshold [1 ppb] would allow certain states to avoid further evaluation of potential emission controls while other states must proceed to a Step 3 analysis. This can create significant equity and consistency problems among states."[45] Since this is the nature of *any* threshold – whether 1 ppb or 1% - we fail to understand how this explanation supports the use of 1%. EPA also claims it changed its position because of EPA's experience with SIP submissions. EPA observes "nearly every state that attempted to rely on a 1 ppb threshold did not provide sufficient information and analysis to support a determination that an alternative threshold was reasonable or appropriate for that state."[46] EPA's reasoning is again off-point. This appears to be a SIP completeness issue, rather than a justification to lower the contribution threshold to 1%. As far as we can determine, EPA just changed its position – which may be more attributable to internal policy and politics than science.

A 1% threshold directly impacts Alabama, Kentucky, Nevada, and Wyoming. EPA modeled contributions between 0.70 ppb to 0.99 ppb for 2023 downwind nonattainment receptors.[47] EPA's model for 2026 shows modeled contributions between 0.70 ppb to 0.99 ppb for Kentucky, Missouri, Nevada, Oregon, and Utah to downwind nonattainment receptors. Using EPA's modeling and assumptions, these states may have not been pulled into the Proposed Rule at all[48] or may have become "unlinked" in 2026 – the year when the Proposed FIP imposes stringent EGU requirements. In these states, EPA's contribution threshold decision is impactful and very expensive, especially given only a 7% downwind benefit.

NRECA supports a 1 ppb threshold. We also suggest EPA could address emissions in upwind states modeled between 0.70 ppb to 0.99 ppb in a different manner. Through the SIP process, these states could examine their emissions profiles, add further support to their SIPs, or

[44] 87 Fed. Reg. at 20073-74.
[45] Air Plan Disapproval; Wyoming; Interstate Transport of Air Pollution for the 2015 8-Hour Ozone National Ambient Air Quality Standards, 87 Fed. Reg. 31495, 31504 (May 22, 2022).
[46] *Id.*
[47] 87 Fed. Reg. at 20071-72.
[48] There are different contribution estimates for contributions to downwind maintenance receptors.

propose emission reductions, if warranted. For instance, EPA allowed consideration of a weight of the evidence approach in the Iowa SIP.[49] A lighter touch would be commensurate with lower contribution impacts of these states and would be consistent with the CAA Section 110.

B. EPA's Air Quality Model contains significant errors that must be corrected.

EPA's model of upwind states' impacts on downwind receptors is a critical element of the Proposed FIP. Unfortunately, the model has numerous flaws, identified in the comments and technical analysis filed in the docket by the Midwest Ozone Group. Although courts grant EPA deference to make modeling choices, there are limits. Where there is "no rational relationship to the characteristics of the data to which it is applied," a model is arbitrary and capricious. *Homer City*, 795 F.3d at 135. Unlike *Homer City*, EPA's modeling does not just have some minor discrepancies that are "small" and "random" like the model the D.C. Circuit upheld for the CSAPR iteration from 2011. *See id.* at 135-36**.**

Alpine Geophysics performed an analysis at the request of Midwest Ozone Group to determine the steps that EPA took to analyze air quality for the Proposed FIP (the Alpine Technical Memorandum).[50] The Alpine Technical Memorandum identifies methodological errors in EPA's approach. Of significant concern, EPA departed from its own guidance by declining to prepare a final air quality simulation (full photochemical air quality modeling run) rather than the simplified AQAT that EPA used instead. The simplified AQAT is a screening analysis that estimates air quality improvements from the proposed control strategies. It is an abbreviated approach in comparison to the full modeling run.

Setting aside model choices, EPA set up its simplified AQAT model to fail. EPA used conflicting EGU inventories in its modeling steps for Steps 1 and 2 (Integrated Planning Model (IPM)) versus use of Engineering Analytics (EA) inventories in Step 3. For example, in the IPM database, as discussed in our generation shifting discussion *infra*, numerous EGUs are mistakenly presumed to be retired or idled. In comparison, EPA's EA inventory contains these

[49] Air Plan Approval; Iowa; Infrastructure State Implementation Plan Requirements for the 2015 Ozone National Ambient Air Quality Standard, 85 Fed. Reg. 12232 (Mar. 2, 2022). EPA back-tracked on this approach by reverting back to a 1% contribution threshold in its final Iowa SIP approval – which was consistent with EPA's 2022 positions for other SIPs. *See* 87 Fed. 9477 (Feb. 22, 2022).
[50] *See* "Review of EPA's Use of AQAT in the Federal Implementation Plan for the 2015 Ozone NAAQS Transport Proposed Rule," Alpine Geophysics dated June 17, 2022 at MOG Comments, Exhibit E.

units.[51] Thus, the post-control emissions budgets from the EA are higher than the IPM-based emission inventories used to prepare the calibration factors for the simplified AQAT. For these reasons, the remedy case is not reliable because it does not provide accurately modeled air quality concentration projections at the downwind receptors due to this discrepancy. In other words, EPA does not have a basis to show that this Proposed FIP resolves *any* states' good neighbor obligations. The Proposed FIP's modeling disagreement results in a failed model that is not reliable.

EPA must correct the modeling inputs and assumptions and re-run its model. From there, the public should have an opportunity to comment on the new analysis in a proposed rule format, prior to finalizing this Rule. To rush to final would deprive the public of an important opportunity to vet EPA's results, contrary to the Administrative Procedure Act.[52] Engaged commenters, such as the cooperative community, need a meaningful opportunity to review inventories as well as EPA's modeling choices and methodology. We urge EPA to follow these legally required steps.

EPA's flawed air quality invalidates its required "over control analysis," which ensures the Proposed FIP is not too stringent. EPA can only require states to reduce emissions as much as necessary to achieve attainment in every downwind state. *Homer City*, 572 U.S. 489, 522 (2014). So doing would be counter to the good neighbor provision. *Id*. EPA must also balance "under control," otherwise its statutory mandate has not been met. The "over control" analysis involves modeling of proposed reductions of upwind emissions based on the Proposed FIP on downwind receptors. On-the-books-controls should be included for both upwind and downwind states. The timelines for reductions from this Proposed Rule and home-state reductions to achieve attainment must be concurrent. We have identified flaws in how EPA accounted for all emission reductions in home states. In addition, EPA failed to consider all reductions the Proposed FIP will cause.[53] For example, EPA's model only accounts for reductions based on state budgets. There will be further reductions from the new concepts EPA introduced through

[51] The Alpine Technical Memorandum contains tables that demonstrate inventory discrepancies. Alpine Technical Memorandum at 6-7 (comparing the IPM 2023 inventory against the EA Budget inventory).
[52] 5 U.S.C. § 553(c).
[53] For further discussion of air quality shortcuts and analytical flaws in EPA's air quality model, please see MOG's comments on this rulemaking, filed in the docket.

dynamic budgeting, bank recalibrations, retirements caused by this Proposed Rule, and the daily NOx limits. This flawed analysis is inconsistent with EPA's legal obligation to refrain from requiring pollution reductions more than needed to achieve downwind attainment or ensure no interference with maintenance. When EPA corrects its air quality model, it must also redo the "over control" analysis.

C. Mobile sources account for a significant portion of upwind emissions but are not targeted for NOx reductions in CSAPR Step 3.

EPA acknowledges mobile sources contribute NOx and volatile organic compounds (VOCs) to downwind monitors. Rather than exploring meaningful NOx reductions, EPA punts.[54] The Proposed Rule states: "EPA notes that its Step 3 analysis does not assess emissions reduction opportunities from mobile sources. The EPA continues to believe that title II of the CAA provides the primary authority and process for reducing ozone-precursor pollutants from mobile sources."[55] EPA acknowledges it could have regulated mobile sources under Title I of the CAA by employing measures such as vehicle inspection and maintenance programs, gasoline vapor recovery, and clean fuel programs.[56] But the Proposed Rule does not explain why EPA passes on mobile source emission reductions in upwind states. Reduction of mobile source emissions would make an impactful difference on ozone transport. Rather EPA opts to take another swipe at EGU sector contributions, despite smaller upwind contributions – in comparison to mobile sources. Squeezing further reductions from EGUs is unlikely to achieve EPA's goals given diminished sector contribution as a whole and smaller opportunities to reduce emissions from a largely well-controlled fleet. EPA should re-evaluate its choice to ignore upwind mobile source contributions.

VIII. EGU NOx Reduction Methodologies (CSAPR Step 3 Approach and Continued in this Proposed Rule) contain inaccurate emission reduction expectations and installation timelines.

In its CSAPR Step 3, EPA selects NOx emission reduction controls for EGUs. EPA has selected SCRs, SNCRs, and combustion controls based on unit size and fuel type. EPA also

[54] 87 Fed. Reg. at 20077.
[55] *Id.*
[56] *Id.* at 20077 n.142.

identifies generation shifting as a reduction methodology. NRECA has identified the following technology concerns.

A. Electric Cooperatives face significantly longer time frames to conduct major outage projects than investor-owned utilities.

With respect to *all* of control device installation capital projects identified in the Proposed FIP, EPA must factor in additional time for electric cooperatives for financing. Cooperatives cannot simply go to investors to obtain funding. The largest financier of cooperative capital projects is RUS, which is an arm of the federal government. Founded by President Franklin D. Roosevelt, RUS has historically served cooperatives, with the mission of electrifying and maintaining critical infrastructure in rural America.[57] RUS financing entails a multi-step process. Prior to project construction, a cooperative must engage its project engineering team to prepare initial scoping and draft a project justification for the projected dollars to be spent. This process involves reaching out to third-party vendors to confirm cost estimates, design, and operational specifications. RUS must approve the Work Plan.

RUS financing requires compliance with the NEPA, which adds additional time at the beginning of a large project. The U.S. Department of Agriculture (USDA) regulates actions financed by RUS requiring environmental review. The environmental review requirements are set forth by NEPA, which require all federal agency actions or approvals go through a standardized environmental review process to evaluate what effect their proposed actions (projects) would have on the environment. Environmental reviews require development of Environmental Reports (ER), Environmental Assessments (EA), or Environmental Impact Statements (EIS) depending on the complexity and scale of the project.[58]

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[57] For more information about RUS and its essential role for the cooperative community, see https://www.rd.usda.gov/about-rd/agencies/rural-utilities-service (*visited June 3, 2022*) ("The Electric Program provides funding to maintain, expand, upgrade and modernize America's rural electric infrastructure. The loans and loan guarantees finance the construction or improvement of electric distribution, transmission, and generation facilities in rural areas. The Electric Program also provides funding to support demand-side management, energy efficiency and conservation programs, and on-and off-grid renewable energy systems. Loans are made to cooperatives, corporations, states, territories, subdivisions, municipalities, utility districts and non-profit organizations.").

[58] The extent of the environmental review is established in 7 CFR § 1970.8.

The environmental review process and timelines depend upon the scope of the project and ultimately what project documents RUS will request the cooperative submit; however, a large control device project is likely to trigger an EA.[59] RUS then reviews the EA or other environmental document and may require additional information, additions, or revisions to the EA during the review process. Ultimately, RUS adopts the EA at the conclusion of the review process. RUS then publishes a public notice of the availability of the EA. The public notice and comment process commences, which would involve notice of the issuance of a Finding of No Significant Impact (FONSI), if RUS makes this finding.[60] Borrowers must wait for the conclusion of RUS's environmental review before taking any action on projects or obtaining RUS financial assistance.[61] Once RUS releases funds, the project engineering design and competitive bidding process may commence. It is also important to note that RUS will also be receiving numerous applications for funding, which will naturally slow the process of providing responses and approvals.

While other financing options may be available for certain types of projects, the interest rates are significantly higher. Electric Cooperatives are not-for-profit organizations, and their end-users of electricity are in rural communities, many of which are disadvantaged. These electric cooperatives and end users must bear the full weight of responsibility to pay for these projects and are very sensitive to rate increases.

EPA must factor in at least an additional 18 months <u>on top of the projected time frames discussed *herein*</u> to allow cooperatives to obtain financing for a large control device installation project such as an SCR or SNCR.

B. Installation of SCRs by 2026 is not achievable given past project data, construction timelines, and available third-party resources.

[59] For reference, *see* Environmental Assessments for other cooperative projects located on the RUS website: https://www.rd.usda.gov/resources/environmental-studies/assessments (visited June 3, 2022).
[60] RUS outlines the environmental review process in detail on its website and provides a step-by-step flowchart of the process. We provide a link to this information for EPA's reference for inclusion into the record: https://openei.org/wiki/RAPID/Roadmap/9-FD-h (*visited on June 3, 2022*).
[61] *See* 7 CFR § 1970.12.

EPA's 2026 time frame (36 months)[62] to install new SCRs is unworkable. Past project data shows three years is inconsistent with real-life installation times. Based on data from past SCR installations, only two units presented time frames close to 30 months, while most time frames took 40 months or more (12 of 18 installations).[63] Of those, five projects took 50 or more months. This past project data presents a best case, which is not today's reality. Rather boilermaker availability is scarce, as a number of contractors have left the SCR business in recent years. For example, a cooperative received a construction estimate of 75 months for SCR installation.[64] For this reason, it is not even reasonable to assume projects can be completed in 40 months.

To illustrate, historically the industry saw the largest number of SCR installations in 2003, totaling over 35,000 MWs of capacity. The Proposed FIP anticipates exceeding 45,000 MWs of capacity in the time frame of one year (Mid-2025 to Mid-2026) for completed projects before the May 2026 ozone season begins. It is not logistically possible due to limited boilermakers to accomplish this volume of installations in the time EPA provides in the Proposed Rule.

[62] 87 Fed. Reg. at 20080.
[63] Technical Report, Figure 5-4. Notably, none of the units presented are at cooperatives. Financing time is not factored into the analysis.
[64] *Id.* at Section 5-3.

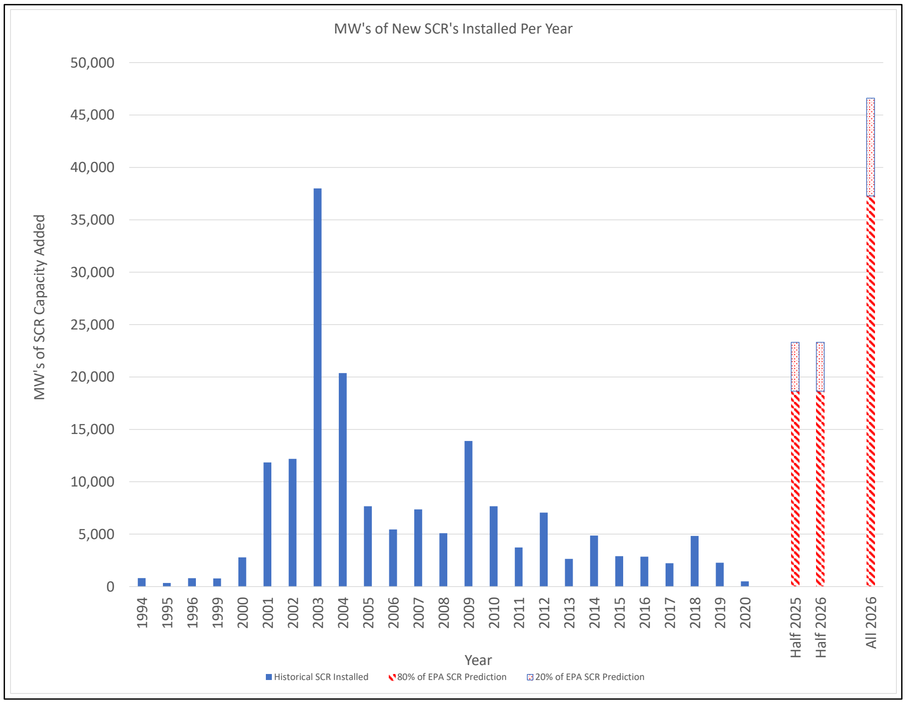

Figure 5-4: Capacity (MW Basis) of SCR

Based on the past retrofit data, at least 40-45 months is needed, which is not achievable with today's inadequate resources.[65] As previously stated, the additional lead time cooperatives require for RUS financing further extends timelines for projects, including SCR installations, an additional 18 months. Given these variables, NRECA proposes EPA revise the SCR installation time frames to provide 58 months, 40 months plus 18 months for RUS financing. In other words, SCR installations should not be expected prior to the 2028 ozone season, at the very earliest, which is still aggressive for many cooperatives to meet.

C. Retrofit of NOx combustion controls cannot be achieved in less than 12 months.

NOx combustion controls cannot be installed by the 2023 ozone season – in less than 12 months. EPA justification is an 11-year-old document[66] that identifies only two installations,

[65] Technical Report, Figure 5-4.
[66] Installation timing for Low NOx burners (LNB), Technical Support Document for the Transport Rule, Docket ID No. EPA-HQ—OAR-2009-0491.

each of which reported retrofit in six months. It is important to note that simply including equipment installation time is not realistic because there are other major project steps.[67]

Our more robust analysis presents six owners, eight stations and eleven boilers. Our timing estimate lays out the specifics of time required for major steps. On average, NOx combustion control projects take 22 months, although some are reported to take up to 60 months. As a result, if project conception started immediately, most units could potentially deploy these controls for the 2025 ozone season.[68]

EPA cannot rely on unrealistic project time frames, removing allocations prematurely. Retrofit of combustion controls should not be expected to be complete until the 2025 ozone season at the earliest.

D. **EPA over-estimates the effectiveness of NOx combustion controls.**

NOx combustion controls cannot achieve 0.199 lbs./mmBtu, particularly for units combusting bituminous coal. EPA must correct this faulty assumption in the Proposed FIP and adjust state budgets to reflect achievable rates.

EPA bases its projection on only 8 bituminous units of which 3 units are valid references for bituminous coal. The dataset is flawed because it claims units are bituminous but instead contains atypical cases of western bituminous, refined coal, or co-fired fuels. We find that only newer generating units using low burner zone liberation rates can meet these rates. The NOx control capability of advanced combustion controls must fully consider coal rank, boiler design features, and operating characteristics.[69]

Feasible NOx reductions for bituminous units are much higher. Using a larger dataset, we have derived average values per fuel-type. However, we note the design "vintage" of the boiler also impacts performance of combustion controls and resulting NOx emissions. These values are an average, as some cooperative units are not able to achieve these rates.

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[67] Technical Report at Section 4-5.
[68] *Id.*
[69] *Id.* at Sections 4.2.2 and 4.4.

Table 4-1. Average Achievable NOx Emissions Rates[70]

Coal Rank	Tangential-Fired	Wall-fired
Bit	0.30	0.32
Lignite	0.20	0.22
PRB	0.15	0.19

NRECA requests EPA evaluate the data presented in its Technical Report and adjust emission rate expectations for NOx combustion controls accordingly – providing sufficient allocations in state budgets to also include a margin for compliance.

IX. EPA has grossly underestimated the costs of NOx Reduction Technologies.

As an initial matter, EPA calculated costs for NOx reduction technologies using a boiler inventory consistent with the boiler population subject to the Proposed FIP. EPA looked at technology costs for boilers in the 25 states subject to the Proposed Rule. Then EPA added nine additional non-upwind states. Addition of these nine states biases the baseline to a lower cost per ton. The results themselves (lower costs) demonstrate the 38 boilers in the nine non-FIP states *are not* representative. EPA should use only states subject to the Proposed FIP to establish a cost baseline representative of the 25 states at issue.[71]

A. Costs: New SCR installation on coal, oil, and gas-fired units.

EPA's estimates of SCR installation costs are underestimates based on dated backup information. EPA projects costs for installation of a new SCR on non-SCR units based on a procedure developed by Sargent & Lundy for both capital and operating costs (S&L Cost Analysis).[72] The S&L Cost Analysis is based on data and analysis from 2004 through 2013,[73] which contains out-of-date costs based on early SCR installations. Many important variables

[70] Technical Report at Section 4.4 (Table 4.1).
[71] Technical Report at Section 3.1.
[72] IPM Model – Updates to cost and Performance for APC Technologies, SCR Cost Development Methodology for Coal-fired boilers, Final Report for Project 13527-002, February 2022. This process is discussed in more detail in the Technical Report at 5.1.
[73] Technical Report at Section 5.1.2.

have changed in the last ten years. Costs for SCR installations have increased, and interest rates have changed. In addition, SCR process conditions (boiler NOx rate and percent NOx removal) have changed, which impact the NOx tons removed.[74]

Re-calculation of SCR installation costs is needed for coal and oil/gas units. NRECA presents and supports an adjusted version of the capital cost relationship proposed by S&L, which is discussed in further detail in the Technical Report. The re-calculation updates the installation cost to 2021 dollars and provides a more realistic cost projection based on half of projects as engineer, procure, construct contracts. The analysis also uses a unit capacity factor consistent with 2021 observed factors. Capital costs also reflect increased costs based on recent data.[75] In the technical review, the authors could not reproduce EPA's results, likely due to the different inventory in units from additional states. Using EPA's assumption articulated in the Proposed Rule and supporting documents, projected cost of the median coal-fired population is $17,508 per ton, exceeding EPA's reference case value of $15,500 per ton.[76] For oil/gas units, EPA's projections were able to be more closely replicated.

Operating costs in the S&L Cost Analysis are underestimates due to the variable operation and maintenance (O&M) for SCR catalyst management. O&M costs vary due to the physical state of the catalyst and ability to achieve a high degree of ammonia-to-NOx uniformity. To achieve an emission limit of 0.05 lbs./mmBtu for new SCR retrofits, sufficient catalyst area velocity is needed.[77] Additional catalyst changeout costs must be added for more than 80% NOx removal by a premium of 9%.[78]

Coal-Fired Units. Results from this study report cost incurred for a unit at the median population of $20,250 per ton for operation at 56% capacity factor, escalating to approximately $28,000 per ton for units at the 90% population. For operation at the 2021 capacity factor, the analysis shows the cost for the median population to be $24,340 per ton, escalating to more than $50,000 per ton.[79]

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[74] *Id.*
[75] *Id.*
[76] *Id.* at Section 6.1.1.
[77] For a compliance margin, 0.04 lbs./mmBtu must be intermittently achieved.
[78] *Id.* at Section 5.1.2.
[79] *Id.* at Sections 6.1.1 and 6.4.

Oil/Gas Units. Cost per unit is estimated at $18,429 per ton for operation at 56% capacity factor, escalating to approximately $32,000 per ton for units at the 90% population. For operation at the 2021 capacity factor, the cost for the median population is $62,661 per ton, escalating to approximately $80,000 per ton for a unit at the 90% population.[80]

Viewing technology projects on a cost per ton analysis does not illustrate the true costs realized by utilities. Utilities typically estimate the total project cost of the project in comparison to the benefit received. For SCR installation projects, the cost of installing an SCR is a multi-million-dollar project.[81] That cost is balanced against the megawatts of generation that the unit provides. It is not surprising that the remaining fleet of non-SCR units are composed of smaller units.

In this graphic, unit generating capacity (bottom axis) presents the differences in affordability of a SCR retrofit. A 100 MW unit has higher dollar per kW project cost. The curve drops sharply between 100 MW to 200 MW, with a more moderate change after hitting 400 MW.

[80] *Id.* at Section 6.1.2.

[81] For example, based on the data in Figure 5-1, for a bituminous coal unit with a 500 MW capacity, the capital cost is $430/kW. Using this value, the rough cost to install an SCR is calculated as $215 million (500 MW x (1000kw/MW) x $430/kW).

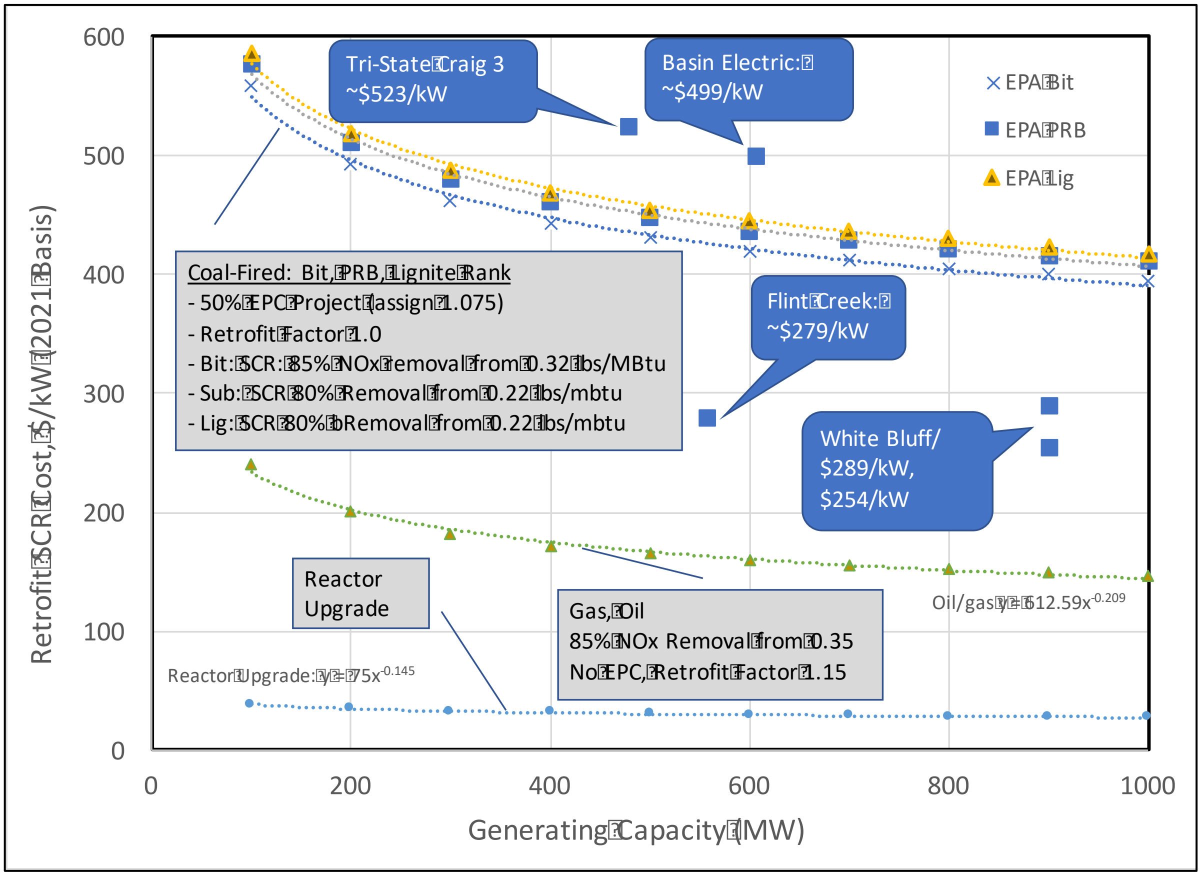

Figure 5-1. Capital Cost vs Capacity Relationship for SCR NOx Control: Coal and Distillate Oil/Natural Gas[82]

This large SCR price tag supports EPA raising the capacity value for SCR installation to 150 MW or higher, rather than 100 MW – which essentially forces smaller units to retire. Units larger than 150 MW can more readily justify SCR installation projects.

In summary, new SCR installations on non-SCR coal, oil, and gas-fired units are substantially more expensive than EPA estimates in the Proposed FIP. Costs must be taken into account. Costs are ultimately borne by end users of electricity. It is important to balance the costs versus the end goal of the Proposed .Rule: To reduce ozone transport from upwind states. Given EGU contribution to downwind nonattainment is minimal, yet costs are extreme. EPA should re-consider its approach to resolving ozone transport issues.

B. Costs: Refurbishing of Existing SCRs

[82] Technical Report at Figure 5-1.

Existing SCRs must achieve the 0.070 lbs./mmBtu target rate to maintain a compliance margin. This requires enhanced O&M practices entailing accelerated catalyst replacement, aggressive catalyst cleaning, and annual tuning reagent injection equipment. In addition, SCRs installed in 2005 and earlier must undertake capital improvements to replace hardware to achieve this rate – including cavities for an addition layer of catalyst. Costs for these additional capital and O&M expenses must be included in EPA's cost estimates.

C. Costs: Coal and Oil/Gas SNCR Retrofits.

SNCRs must be installed on coal-fired units less than 100 MW and to oil/gas units greater than 100 MW of capacity that emit more than 150 tons of NOx annually. Like SCR installation, the SNCR installation costs were re-calculated similarly, as presented by the Technical Report.

Coal-Fired Units. The re-calculated SNCR installation costs found a median population of $15,000 per ton for operation at 56% capacity factor, which increases to more than $40,000 per ton for units at the 90% population. If operation is at the 2021 capacity factor, the cost is $67,432 per ton. In contrast, EPA found a cost per ton of $2,220 as a cost for restarting idled units.[83]

Oil/Gas-fired Units. The recalculated cost is $27,237 per ton for operation at 56% capacity factor, escalating to more than 100,000 per ton for units at the 90% population. When using a 2021 capacity factor, the cost is $117,628 per ton up to more than $250,000 per ton at the 90% population. EPA reports a much lower cost per ton, with the highest cost example being a 100 MW unit operating at 26% capacity factor at $16,100/ton.[84]

D. Costs: Combustion Controls.

EPA claims NOx combustion controls will only cost $1,600/ton. We have determined actual cost is much higher. Using the capital, fixed O&M, and variable O&M provided by EPA in the IPM 5.13 documentation,[85] the total cost of installing advanced low NOx firing equipment

[83] Technical Report at Section 6.4.
[84] Technical Report at Section 6.1.2.
[85] https://www.epa.gov/sites/production/files/2015-07/documents/chapter_5_emission_control_technologies_0.pdf

to a tangential-fired and wall-fired 300 MW boiler operating at 10,000 Btu/kW and 56% capacity factor is $3,345,200 and $2,055,529, respectively, using a 2021 escalated basis. On a per ton basis, the wall-fired boiler burning bituminous call incurs a cost of $4,506/ton to lower NOx from 0.40 to 0.30 lbs./mmBtu. The tangential-fired boiler burning bituminous coal incurs a cost of $2,793/ton to lower NOx from 0.35 to 0.25 lbs./mmBtu.[86]

X. Generation Shifting is fatally flawed and should be eliminated as a NOx Reduction "technology."

The Proposed FIP uses generation shifting across an entire state to achieve further NOx reductions. These reductions are applied, in turn, to reduce state budgets, which forces down unit-level allocations to significant levels in many states. EPA's model diverges from the reality of utility markets. It must be struck from the Proposed Rule.

A. EPA has recognized that cost and economics justify a more limited use of modeled generation shifting.

In the past, EPA used generation shifting in a more limited manner. The court in *Wisconsin* discussed EPA's limited use of generation shifting which it found did not alter state budgets. *See*, *e.g.*, *Wisconsin v. EPA*, 938 F.3d 303, 330 (D.C. Cir. 2019).[87] EPA used generation shifting in the 2015 Revised CSAPR Update Rule but only to a minimal extent of "approximately 2 percent of baseline emissions for each year."[88] The 2015 Revised CSAPR Update Rule limited generation shifting to "price level consistent with control operation," and "[i]t does not factor in generation shifting reduction potential that may be attributable to incremental new builds or incremental retirements."[89]

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[86] Technical Report at Section 4.4.

[87] *Wisconsin*, 938 F3d at 330 ("Industry Petitioners make no showing that the idling assumption actually altered State emissions budgets. EPA used the Integrated Model only to determine the delta between a state's baseline case and the control case, which it then applied to the state's historical 2015 emission rates. Because any projected idling was held constant between the baseline case and the control case, it could not affect how much units were expected to reduce their emissions relative to their historical baseline. *Cf*. 81 Fed. Reg. at 74,547.").

[88] Proposed CSAPR Update Rule, 85 Fed. Reg. 68964, 69009 (Oct. 30, 2020). EPA adopted this approach in the Final Rule. Final 2015 CSAPR Update Rule, 86 Fed. Reg. 23054, 23096 (Apr. 30, 2021).

[89] Final 2015 CSAPR Update Rule, 86 Fed. Reg. at 23101.

In response to comments, EPA justified its more limited generation shifting approach to not push beyond levels commensurate with emission controls. The 2015 Revised CSAPR Update Rule states:

> With respect to generation shifting to existing generation resources with excess capacity, again, this rule already incorporates a certain amount of such generation shifting at cost levels representative of the other control technologies selected to quantify the state emission budgets in this rule. EPA believes that this degree of emission reduction through generation shifting is appropriate to include under the step 3 multi-factor analysis for the circumstances and compliance timetable currently presented by the 2008 ozone NAAQS, particularly the finding that downwind receptors will be resolved under this NAAQS by the 2025 ozone season.[90]

EPA then recognizes using greater generation shifting is possible (to lower or zero emitting assets as well as construction of new assets) but "cost, timing, and economic considerations are generally of a greater magnitude and complexity in this context."[91]

It is not clear why EPA departed from its approach from last year's rulemaking. In the Proposed FIP, EPA claims it followed the same approach as prior CSAPR rules.[92] However, there are significant reductions in state budgets due to EPA's model, presented *infra*. In addition, EPA uses a methodology in its model – with additional runs – that were not present before. It is inaccurate to suggest the Proposed FIP's approach is consistent with prior ozone transport rulemakings.

EPA asks for comment on whether generation shifting is required to eliminate significant contribution. It was not possible in this limited comment period to technically respond to this request by re-running EPA's air quality model without generation shifting. Yet it is evident EPA has many reliable and technologically proven choices available to reduce transport emissions. For example, we continue to suggest EPA should have explored mobile source emission reductions through Inspection and maintenance (I/M) programs or otherwise. It is arbitrary and

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[90] *Id.* at 23096. EPA does suggest that IPM can provide realistic and reliable assessments of the degree of generation shifting that may be accomplished at different cost levels. EPA ultimately finds that this larger degree of generation shifting is not necessary to meet the Proposed Rule's goals under the 2008 NAAQS. *Id.*

[91] *Id.*

[92] 87 Fed. Reg. at 20082 ("The EPA notes that its treatment of generation shifting here is consistent with the prior CSAPR rulemakings and is grounded in statutory authority.").

capricious to rely instead on a flawed generation shifting model as the means to achieve EPA's goals.

B. Generation shifting is not available to smaller systems.

As an initial matter, generation shifting is not a "technology," as it is not an available strategy for the utility owner to reduce its unit-level ozone season NOx emissions. The modeled reductions are hypothetical. EPA's model is not comparable to post-combustion controls that can be tested to assure actual NOx reductions. In reality, EGUs with smaller systems or single-unit ownership – can only reduce unit runtime commensurate with NOx allocations and seek to buy power to make-up the shortfall.

Most cooperatives are defined as "small entities" under Small Business Administration size standards and have a smaller generation system to serve member needs. Cooperatives do not have a portfolio of assets from which to pick and choose dispatch during summer months. Within the limited cooperative portfolio, assets cannot necessarily be substituted one for another due to transmission lines and geographic location. Notably, cooperatives serve vast, less populated geographic areas, so assets are frequently spread out. Municipalities and single-plant owners, under power purchase contracts, are even more constrained. For these practical reasons, cooperatives often cannot generation shift. Their only option is to purchase power. Power purchases, unhedged, may not be economically feasible, especially during the ozone season when capacity is diminished.

C. A flawed model is not a reliable basis to reduce state budget NOx allocations.

EPA's generation shifting model bears no semblance to the reality of generation dispatch. NRECA examined how generation shifting affects nine example states.[93] We have identified numerous flaws in EPA's model dataset and assumptions. However, EPA's approach is difficult to follow and lacks transparency. The following flaws must be considered.

1. The Generation Shifting Base Case is in error – causing the entire model to produce flawed results.

[93] The short comment period dictated a more limited analysis.

Generation shifting is based on the EPA IPM of regional breakdowns of net energy for load in each of the 67 IPM U.S. regions. The model contains three IPM runs to reach final results: the Base Case, Run 1 and Run 2. In the State Budget Setting process, Generation Shifting is the third and final step in determining state budgets. It is used to further remove allocations from the budgets.

The Base Case is the foundation for the entire model. It is the most critical, as a flawed Base Case cannot produce reliable results. In this case, the Base Case has multiple flaws. It fails to represent an accurate generating unit profile of the states we reviewed and likely the remainder of the 25 states we did not have an opportunity to review.

The Base Case retires units that have no plans for retirements. For the nine states our technical support examined, IPM retired 32 coal units representing 9.7 GW of capacity in 2023. Owners of these 32 units have not announced retirements. In fact, nine units (6.6 GW) are SCR-equipped. In addition, IPM idled 42 coal units representing 14.9 GW of capacity lost in 2023 Base Case. Of these 42 units, 17 units (8.5 GW) are SCR-equipped and therefore can achieve an average ozone season NOx rate of 0.07 lbs./mmBtu. EPA needs to correct these errors if it is going to be used in transport rule formulation.[94]

Results of the nine-state study are summarized in Table 8-1, concerning the IPM Base Case by state. IPM has slightly greater than 28% of the operable coal capacity idled in the nine-state study region during the 2023 Ozone Season.

Table 8-1. IPM 2023 Retired and Idled Coal Capacity in the Nine-State Study Region (MW)[95]

State	IPM Operable Coal Capacity	IPM Year-Round Idled Capacity	IPM Ozone Season Idled Capacity	IPM Retired Coal Capacity
AR	5,105	1,817	0	0
IN	11,147	1,118	4,252	0
KY	8,890	1,286	1,017	0
MO	9,417	275	0	240
OH	10,163	136	751	0
PA	1,964	112	767	6,958

[94] Technical Report at Section 8.1
[95] Technical Report at Table 8-1.

TX	17,534	9,632	0	0
WV	11,220	520	80	0
WY	3,830	0	530	2,505
TOTAL	79,270	14,896	7,397	9,703

By removing generation – either by idling or retiring – that generation is not available in the model for later Runs. In other words, generation cannot shift to units the model assumes do not exist. Instead, the model projects generation shifted to sources not covered in the Proposed Rule, such as non-fossil, storage, and industrial facilities, even though many of these eliminated candidates are well-controlled low NOx emitting coal units.

The result of the flawed Base Case is a conflict between EPA's State Budget Setting Engineering Analytics and IPM Policy Case in 2026 NOx reduction potential. In the Engineering Analysis, EPA estimates 64,000 tons of NOx reduction potential in 2026 from 42 GW[96] of SCR retrofits on coal and 19 GW of SCR retrofits on oil/gas steam units. In contrast, IPM used for generation shifting projects a 47,000 ton NOx reduction in 2026 from 32 GW of EGU capacity being retrofitted with SCRs. The difference in these estimates for NOx reductions illustrates the problem with the Base Case – IPM inaccurately assumes idled or retired capacity does not exist in 2026. The IPM Base Case does not present an accurate generation profile.[97]

2. **The Generation Shifting Model assumes the free flow of electricity across states and regional reliability organizations and all transmission constrained areas.**

Although electricity flows freely in the transmission infrastructure, there are practical constraints posed by equipment capabilities, transmission line availability, and regional reliability organization (i.e., RTOs or ISOs) market behavior. As a primary matter, when transmission is not adequate to move generation from a plant to an area of energy need, the power cannot be delivered.[98] Unless the system is designed to support it, a plant at one end of a

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[97] Technical Report at Section 8-1.
[98] This discussion addresses the physical and technical capabilities of the transmission system to deliver power, not organized market mechanisms that may be used to allow power to be provided from alternative resources (at higher prices) as needed notwithstanding transmission congestion or unavailability.

state cannot substitute for lost generation from a plant at the opposite end. Lines were put in place based on historical generation need, plant locations, and system geography. Although RTOs have undertaken improvement and construction of transmission facilities in order to provide greater flexibility of power flows, this is a lengthy, tedious process. Transmission projects are subject to policy issues often regarding cost and siting. Therefore, at present, many areas exist – especially in rural settings served by cooperatives – in which the current transmission infrastructure is not adequate and/or the generation resources to the area have little reserve buffer. As not for profit consumer owned entities, cooperatives build generation and transmission to meet consumer owner needs on slimmer capacity margins.

In addition, power does not necessarily flow freely from one RTO to another, as assumed by EPA.[99] In other words, if an asset from one RTO is not operating, the generation is not necessarily picked up by a plant in a different RTO *even if* transmission infrastructure permits. RTOs serve their own region's needs first. Only where excess capacity exists after members get the first cut, can the capacity be purchased in the market by a non-member. In the open transmission reservation system, capacity cannot be purchased for a specific transmission path unless it is available.[100] If the path is fully subscribed based on RTO member needs, that generation cannot substitute for an idled asset outside of the RTO. There are also differences in RTO markets, rules and capability that make the free flow of power from one to the other challenging.[101] These "seams" issues have not been taken into account in the Proposed Rule.

EPA's generation shifting model completely ignores energy market rules and transmission infrastructure limitations. Its simplicity fails. It is not realistic to assume a comprehensive redesign of the entire flow of power within a state. An accurate model would

[99] The inability to transmit power across areas is even more exacerbated between regions. As a DOE NREL study observed, "[t]he three major components of the U.S. power system—the Western Interconnection, the Eastern Interconnection, and the Electric Reliability Council of Texas—operate almost independently of each other. Very little electricity is transferred between the interconnections due to limited transfer capacity." DOE NREL Interconnection Seams Study, available at [Interconnections Seam Study | Energy Analysis | NREL]

[100] As previously discussed, NERC has projected capacity shortfalls in many areas for this summer. Lack of capacity is certainly not hypothetical. *See* NERC 2022 Reliability Report.

[101] *See, e.g.,* FERC Docket No. AD21-13-000, Climate Change, Extreme Weather, and Electric System Reliability, Notice Inviting Post-Technical Conference Comments issued August 11, 2021, noting that panelists noted the importance of coordinating transfers across seams in RTO regions, and FERC posed several questions regarding current coordination and possible improvements.

have to include transmission details and RTO market complexities. Otherwise, the model output is purely illusory.

3. The Model shifts generation outside of the CSAPR program.

IPM shifts generation outside of the CSAPR program. Non-program units include units such as storage (energy or pump), landfill, reciprocating units, and non-fossil capacity types. The outcome of this assumption leads to further emission reductions by zeroing out allocations necessary to run those CSAPR fossil units in state budgets. By so doing, EPA effectively shuts down the units. Those unit allocations are removed from the state budgets and assumed to be replaced with assets outside of the program.

4. In EPA's own analysis, there are unexplained discrepancies.

EPA's analysis shows inconsistent data, which our technical support identified in the nine state analysis they performed. For 2023 generation shifting, there are discrepancies between the Proposed Appendix A Proposed Rule State Budget Calculations and Engineering Analytics Spreadsheet and Appendix D-1 of the Ozone Transport Policy Analysis Proposed Rule TSD. As shown in Table 9-7, six of the nine states show differences in the number of tons shifted due to generation shifting, based on comparing the two sources. This internal disagreement in calculations is further evidence of the flaws in the Proposed FIP's generation shifting analysis.[102]

Table 9-7. 2023 Generation Shifting Discrepancies[103]

State	Appendix A Budget Shifting Tons	Appendix D-1 Budget Shifting Tons
AR	38	38
IN	**335**	**326**
KY	1,213	1,213
MO	**668**	**444**
OH	765	765
PA	**409**	**309**
TX	**1,422**	**1,190**
WV	**828**	**547**
WY	**376**	**958**

[102] Technical Report at Section 9-8.
[103] *Id.* at Table 9-8.

5. The Model's generation shifting outcome causes unintentional, nonsensical results.

The Proposed FIP describes Generation Shifting as biasing generation and NOx emissions from higher to lower NOx emitting sources. However, our nine-state analysis yields inconsistent results that would not take place in the marketplace. EPA has removed allocations, particularly in 2026, from state budgets due to this model. The result is well-controlled units with SCRs must restrict operations (capacity factors) to comply. There are limits to SCR-technology. These units cannot use control technology to reduce enough NOx to make up the shortfall caused by generation shifting reductions. The outcome of the model may be dispatch of higher emitting, older gas-fired units typically only used as peaking units. This is not an outcome the Proposed FIP should force.

In our technical analysis, Table 9-8 demonstrates the allowance shortfalls – to which generation shifting is a significant factor, among other faulty assumptions discussed in Section 9 of the Technical Report. Many units will not have sufficient allowance allocations in 2023. The Technical Report estimates an overall allowance shortfall of 6,310 allowances during 2023 Ozone Season.

Table 9-8. EGU 2023 Ozone Season Emission and Allocations by State

State	2021 Ozone Season Emissions	2023 Ozone Season Emissions	2023 Allocations	Deficit/Overage
AR	8,955	8,047	8,889	842
IN	14,162	12,595	11,111	-1,484
KY	14,571	14,146	11,640	-2,506
MO	20,388	11,705	11,857	152
OH	11,728	9,961	8,077	-1,884
PA	12,792	8,488	8,782	294
TX	42,760	37,595	38,206	611
WV	14,686	13,607	12,478	-1,129
WY	11,643	10,331	9,125	-1,206
Total	151,684	127,615	120,165	-6,310

The scarcity of allowances coupled with allowance bank restrictions will result in very costly allowances for purchase. We are already seeing sky-rocketing Group 3 allowance prices.

The larger issue at hand is reliability. It is unclear what will take the place of this lost capacity next year.

D. Generation shifting must be limited, otherwise it yields unfair results as to cost, contrary to the Court's opinion in *Homer City*.

Generation shifting must be limited, otherwise it yields unfair results as to cost, contrary to the court's opinion in *Homer City*. EPA asserts its generation shifting model produces a reliable projection. However, if we assume these projections of unit operation shifts, costs are not uniform among units. There are "winners" (which may be outside of the CSAPR Program) and "losers" across a state. The generation shifting analysis removes allocations by assuming certain units are either not going to be dispatched or will be dispatched at a lower level. Some of these units are well-controlled SCR coal-fired units.

In *Homer City*, the Court agreed with the use of the "cost of preventing emissions" as the allocation method of emissions between contributing states, regardless of each states' contribution to downwind nonattainment. *Homer City*, 572 U.S. 489, 519 (2014). As part of this analysis, the Court engaged in a fairness comparison between units that had not yet implemented pollution controls of the same stringency as their neighbors. *Id.* at 519-20. The Court recognized the inequity between a plant with modern controls versus a less controlled plant because the more controlled plant would be "compelled to spend far more per ton of reductions because they have already utilized lower cost pollution controls." *Id.* at 520. The Court explains the cost/ton uniformity avoids this result because the less controlled plant must spend more to comply with the rule by updating its controls. However, the fairness analysis between a controlled and uncontrolled unit fails when applying generating shifting as a technology. Our technical analysis demonstrates many coal units with SCRs lose generation in favor of the model's shift to lower emitting gas units or non-CSAPR renewable units. It does not matter that the plant invested in modern controls. Equity between controlled and non-controlled units fails. For this reason, the Proposed FIP's use of generation shifting is contrary to the Supreme Court's technology fairness assumptions.

E. Generation shifting cost calculations are based on EPA generic assumptions that are likely not representative of actual NOx reduction costs.

The Proposed FIP fails to properly assign a cost to generation shifting as a control technology, even though generation shifting plays a significant role in reducing the allocations many state budgets. Cost calculations are based on "costs levels that are representative of the emissions control technologies evaluated in the multi-factor analysis."[104] This statement is not transparent but implies that EPA used costs it assigned to the individual control technologies (e.g., SCR, SNCR) exclusively. So, essentially, EPA did not assign a cost directly to generation shifting as a technology. This is an error. To illustrate, the total nine state 2023 budget shortfall is 6,310 allocations. If these shortfalls are due to generation shifting, the cost of purchasing these missing allocations back for utilities would run roughly $189 million dollars, at the current Group 3 allowance price of $30,000.[105] Plainly, the Rule ignores this very direct cost to utilities due to the generation shifting step.

F. Generation Shifting: Conclusion.

NRECA recommends EPA eliminate the Generation Shifting step in the State Budget setting process. EPA should adopt the Optimized Baseline values as the final state budget numbers and recalculate the remaining state budgets accordingly.

XI. The New Design CSAPR Concepts are not justified or necessary.

EPA introduces new "features" into the CSAPR program.[106] EPA's justification is to "help maintain control stringency over time and improve emissions performance at individual units."[107] EPA seeks assurance that existing pollution controls will be operated during the ozone season.

The Proposed FIP acknowledges that the new "enhancements" will reduce the flexibility of the program, but EPA explains that "the inherently greater flexibility of a trading program" continues to favor use of a trading program instead of other prescriptive means of lowering emissions from EGUs.[108] We agree that a trading program is an effective, proven means to address ozone transport using mass emissions. Yet we disagree that the Proposed FIP preserves

[104] 87 Fed. Reg. at 20081.
[105] On June 15, 2022, the S&P Global price for Group 3 allocations was $32,750.
[106] 87 Fed. Reg. at 20039.
[107] *Id.*
[108] 87 Fed. Reg. at 20105.

any semblance of flexibility. In effect, the FIP would use the shell of the CSAPR program in name only. The curtailment of allocations would strip "flexible" trading. Not only do tight budgets and the generation shifting reductions contribute to allowance shortfalls, but EPA's new concepts trim any remaining "fat," if there really will be any remaining.

None of these features are necessary. EPA deems allowance trading programs as "highly effective." NRECA agrees. EPA stated in the Revised CSAPR Update Rule, which did not have these new enhancements:

> These trading programs have been demonstrated to be highly effective at achieving emission reductions. For instance, as discussed in greater detail below, EPA has previously demonstrated that in the first CSAPR Update compliance period (i.e., the 2017 ozone season), the budget drove sources, nearly uniformly, to operate their controls for that control period.[109]

In the past, commenters have claimed that a trading program will not lower emissions on high ozone days. EPA countered that 2017 data shows that the CSAPR program and other regional trading programs "can provide continued incentives for control operation in a full-remedy context, so long as the budget is sufficiently stringent."[110] EPA dispelled the notion that the majority of EGU operators are choosing not to operate SCR controls. Data from 2017 showed that the 274 SCR-controlled units were operating at an average emission rate of 0.088 lbs./mmBtu.[111] EPA's data did not support the allegations of commenters that operators are turning off controls. EPA, in this rulemaking, recognizes that past studies showed a lack of evidence of SCR non-operation but postulates that "this problem could become more prevalent in future years relevant to this action."[112] The Proposed FIP provides no reasonable basis for this prediction.

Most EGUs have enforceable permitting requirements to prohibit turning off a control device. A significant number of units were involved in EPA's New Source Review enforcement initiative that began in the early 2000s. To settle, EPA required utilities to agree to control device "continuous operation" provisions for SCRs. In addition, the Consent Decree NOx limits,

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[109] 86 Fed. Reg. at 23117.
[110] *Id.*
[111] *Id.* EPA performed this analysis as part of the Maryland/Delaware CAA section 126(b) action. It also found that 261 of 274 units had ozone-season emission rates below 0.20 lbs./mmBtu.
[112] 87 Fed. Reg. at 20110.

typically 0.080 – 0.100 lbs./mmBtu, could not be met without SCR operation to maintain the 30-day rolling average.[113]

These units currently have Consent Decree-based permit requirements in their Title V permits. If operators elect not to run SCR controls consistent with manufacturers specifications and good engineering practices, they are in violation of their permit. Consent Decrees are but one CAA tool in EPA's and permitting authorities' arsenals to ensure SCRs continuously operate. NAAQS nonattainment, Regional Haze, New Source Review, and state operating permit requirements are among the means *presently in EGU Title V permits* to ensure SCR operation. EPA should acknowledge that these federally enforceable measures are in place exactly for the purpose of assuring control device operation. It is not necessary to impose duplicative requirements on this highly regulated sector.

Regardless of our theoretical objection to the *need* for the new features, NRECA, through its technical experts, has reviewed these newly proposed concepts and has the following critiques.

A. **Dynamic Budgeting methodology, as proposed, is not workable.**

EPA proposes dynamic budgeting to begin in ozone season 2025 and annually thereafter. EPA's methodology begins with adjustments based on changes to the "baseline EGU inventory" such as retirements/repowering. EPA then adds a new element of variability to the dynamic budgeting calculation: Adjustments based on unit heat inputs.[114] The heat inputs of units within a state for *one ozone season*[115] will be summed. The following year's state budget will be adjusted based on that prior year's heat inputs, which reflect unit dispatch and run-time. EPA does not apply generation shifting modeling to the dynamic budget process.[116] As discussed in Section VI.A, state budget allocations are capped at Summer 2021 heat inputs. Units cannot

[113] *See* Table 3-24 New Source Review (NSR) Settlements in EPA Platform v6 at https://www.epa.gov/sites/production/files/2019-03/documents/table_3-24_new_source_review_nsr_settlements_in_epa_platform_v6.pdf (visited June 7, 2022).
[114] 87 Fed. Reg. at 20108. EPA proposes the use of "most recent available reported data" for the state budgets for the following ozone season year.
[115] While unit portions of the state budgets are based on an average of multiple years, dynamic budgeting would adjust state budgets based on one year.
[116] 87 Fed. Reg. at 20108. NRECA agrees that application of generation shifting yields a flawed result. It should be eliminated from this rulemaking altogether.

operate at higher heat inputs due to the cap. For this reason, the only mathematical output of the dynamic budgeting process is to push heat inputs further downward.[117]

Dynamic budgeting is unworkable for the following reasons:

<u>Relying on one ozone season will generate inconsistent results</u>. One ozone season is a small snapshot from which to dictate future unit behavior.[118] Generation asset use can vary greatly from year to year based on many outside factors that impact heat input, such as weather, forced outages, and gas prices, all of which are unpredictable. An ozone season in which gas prices are low may curtail coal unit dispatch; however, these units may need to be dispatched in the following ozone season if market circumstances change. Ratcheting down budgets based on heat input would hand cuff these units the following year. Coal-fired units would not have the flexibility to respond to the demand without sufficient NOx allocations.

<u>Maintaining a generation mix is essential to grid reliability</u>. As NRECA CEO Jim Matheson testified to the Senate: "The ongoing energy transition must recognize the need for time and technology and be inclusive of all energy sources to maintain reliability and affordability." Dynamic budgeting will, in practice, force out coal units, that emit more NOx than gas units, by pressing budgets down. Without baseload resources, there is a substantial risk of grid reliability.

<u>Using one ozone season to shrink state budgets is inconsistent with prior CSAPR methodology</u>. Previously, EPA addressed unit retirements by removing those allocations from source accounts after five years and by periodically recalculating budgets when a new trading rule generation took root. For example, the Revised CSAPR Update Rule from 2021 did not put a regular budget recalibration in place.[119] Instead, that rule relied on programmatic elements to

[117] Since unit capacity factors are capped at 2021 heat inputs, they will not have enough allowances to run at higher heat inputs during the ozone season.
[118] CSAPR Update Rule at 23120 ("As in the CSAPR Update, EPA combined historical data with IPM data to determine emission budgets.") In that rule, EPA discussed 2020 data during the COVID pandemic and recognized that unusual ozone seasons may not be appropriate as a base budget year. In the 2016 Rule, EPA used the historic emissions baseline period established for ozone-season NO_x is 2008 through 2015, which captured the unit-level emissions before and after the start of CAIR and the original CSAPR.
[119] 86 Fed. Reg. at 23132 ("[T]he allowances formerly allocated to units with scheduled future retirements will be removed from the budgets for control periods after the scheduled retirements instead of being added to the new unit set-asides for the future control periods. EPA has not included a mechanism in this rule to adjust the emission budgets over time to account for either units with unscheduled future

adjust budgets such as retirement requirements and new unit set-asides for added generation. In this way, the Revised CSAPR Update Rule incorporated a strategy to adjust state budgets commensurate with the changing EGU fleet.

Dynamic budgeting is not necessary. The CSAPR framework already contains components to address federally enforceable changes to state inventories (e.g., retirements, repowering) via new unit set-asides and removal of allocations for retirements. These concepts address EPA's concerns regarding changes in the fleet. Program stringency will be maintained without dynamic budgeting.

Emissions reductions from dynamic budgeting are not necessary to attain or maintain NAAQS in downwind states. Based on our analysis in the brief comment period, we do not believe that EPA's model included NOx reductions from dynamic budgeting. Therefore, dynamic budgeting is not a concept that is required to achieve EPA's projected attainment at downwind receptors and produces an overcontrol scenario.

Treatment of Retiring Units. Elimination of allocations from retired units addresses the changing generation mix. Related to dynamic budgeting, this concept is embedded in the CSAPR program to update budgets based on the changing EGU fleet. Previously, CSAPR allowed a source to keep allocations for five years from retirement (two consecutive control periods of nonoperation plus three years). The Proposed FIP shortens allocation retention to "only two full control periods of non-operation."[120] This approach fails for several reasons. First, nonoperation is not the same as retirement. Idling may occur for various reasons such as changes of ownership or market conditions. In fact, the Proposed FIP adds a layer of complexity to nonoperation conditions. Where non-SCR units do not have enough time or financing to add controls, operators may be forced into nonoperation in future ozone seasons. In addition, the proposed budgets are tight. They will force units off-line during summers that will continue to be needed for capacity in winter months. It is also possible that the cost to dispatch certain units – due to pricey CSAPR allowances – may lead to an operational unit, bid into the market, that is

retirements or the construction of unplanned new units and is not prepared at this time to reduce the budgets for units with unscheduled future retirements without consideration of whether and how to increase the budgets for the construction of unplanned new units.").

[120] 87 Fed. Reg. at 20129.

not chosen for dispatch.[121] The heat input of that viable unit would be zero. These units are not "retired," however; the CSAPR program would eliminate them from the allocation pool. Moreover, we note, in support of a longer retired unit allocation approach, that retaining CSAPR allocations for a longer time period may incentivize retirements. We are aware of numerous instances in which the CSAPR program was a meaningful factor as a retirement benefit considered in company strategy. With depleted allocation banks and tight budgets, we anticipate such an incentive would only be stronger in coming years.

Conclusions. NRECA advocates for removal of dynamic budgeting. In the alternative, at the very least, dynamic budgeting should be based on an average of at least three ozone seasons. It also should not be an annual concept. With respect to retiring units, EPA should retain the current CSAPR retired allocation approach of five years (2 consecutive control periods of nonoperation plus three years). In addition, "retired" units should be based on annual heat input rather than performance during the ozone season.

B. **Predicted state budget shortfalls prove that routine Bank Recalibration is unwarranted**.

EPA proposes bank recalibration beginning in August 2024 and annually thereafter.[122] Routine recalibration entails EPA "taking" allowances from banks above a target level of 10.5 % of the sum of all state emissions budgets for the current control period. EPA's goal is to "prevent any surplus of allowances created in one control period from diminishing the intended stringency and resulting emissions reductions of the emissions budgets for the subsequent control periods."[123] EPA justifies this suggested bank restriction by claiming that temporary allowance surpluses will weaken the trading program's incentives, such that operators may not optimize or operate their control devices.[124]

NRECA opposes an automatic bank recalibration for the following reasons:

[121] The ability to bid in capacity is essential to the RTO model and provides a source of income for many cooperatives, regardless of whether that unit is chosen to run.
[122] 87 Fed. Reg. at 20109.
[123] *Id.*
[124] *Id.*

Routine bank recalibration is not necessary to maintain the stringency of the CSAPR Program. Table 9-8, entitled "EGU 2023 Ozone Season Emission and Allocations by State" in Section VI *supra* illustrates allocation shortfalls in six of nine example states in 2023. The three states without shortfalls only had minor surpluses. The overall 2023 allowance shortfall for the nine states together is 6,310 allowances. The shortfall in 2026 is even more egregious, likely the result of generation shifting, based on our technical experts' results in Table 9-9.

Table 9-9. Kentucky and Texas EGU 2026 Ozone Season Emissions and Allocations[125]

State	2021 Ozone Season Emissions	2026 Ozone Season Emissions	2026 Allocations	Deficit/Overage
KY	14,571	11,794	7,675	-4,119
TX	42,760	30,975	22,195	-8,780

It is plainly not realistic to pretend there will be any allowance surplus, particularly enough to permit changes in control device operation. Regardless of the sufficiency of allowances, enforceable permit requirements require continuous operation of SCRs and SNCRs at optimized rates, regardless of allowance shortages. Any banked allowances will be needed to make up for projected budget shortfalls. We also reiterate that EPA has found a lack of evidence that a large number of sources are turning off SCRs.[126]

Exorbitant Group 3 allowance prices demonstrate future program stringency. Since the Proposed FIP's release, Group 3 allowance prices have risen to $32,750.[127] Keep in mind that one allowance authorizes the emission of one ton of NOx. Pricing is indicative of a tightly budgeted program without surpluses.

Annual removal of banked allowances cuts against incentivizing utilities to improve NOx emissions. Past transport trading programs allowed banking as a benefit to encourage operators to explore means to reduce NOx further. EPA acknowledges this benefit in the Proposed FIP.[128]

[125] Technical Report at Table 9-9.
[126] 86 Fed. Reg. at 23117.
[127] On June 15, 2022, the S&P Global price for Group 3 allocations was $32,750.
[128] 87 Fed. Reg. at 20109.

In the Revised CSAPR Update Rule, EPA lauds the flexibility of a mass-based trading program.[129] A key feature to maintaining this flexibility is banking.

Routine bank recalibration was not used in past ozone transport programs. Instead, EPA found other means of addressing bank stringency on a need-basis. EPA has regularly recalibrated allowance banks with each iteration of the program. The Program was last recalibrated last summer 2021. It was previously recalibrated in 2017. These periodic recalibration events removed accumulated, banked allocations. Banks are already depleted.

Routine bank recalibration will cause emission reductions that are not necessary to attain or maintain the 2015 Ozone NAAQS in downwind states. Like dynamic budgeting, EPA's model does not include reductions due to bank recalibration. Bank recalibration is unnecessary to achieve the goals of this rulemaking and creates another overcontrol scenario.

Conclusion. NRECA supports removal of routine bank recalibrations from the Proposed FIP. It is not needed to assure program stringency or to reduce upwind states contribution to a level below the appropriate threshold, especially given the other features proposed.

C. **Unit-Specific Daily Backstop Rates are not achievable and are not necessary to meet good neighbor obligations.**

One of the most controversial, flawed new concepts in the Proposed FIP is the daily backstop rate. The daily rate applies to coal-fired EGUs of 100 MW or more[130] beginning in 2024 for SCR-equipped units. Non-SCR units must contend with the daily rate beginning in the 2027 ozone season.[131] EPA sets a daily rate of 0.14 lbs./mmBtu based on an average rate of 0.08 lbs./mmBtu over the ozone season.[132] If a unit exceeds the daily rate, the unit must surrender allowances at a 3 for 1 ratio.

[129] 86 Fed. Reg. at 23094 ("Furthermore, because the emission reduction obligation is implemented through a mass-based trading program, these sources (and all others in the newly established Group 3 trading program) have abundant flexibility to choose other means of complying with their emission budget.").
[130] CFB units are excluded from the daily rate. We encourage EPA to insert a regulatory provision in the applicability section of the rule to exclude units that do not have to install SCRs.
[131] 87 Fed. Reg. at 20110.
[132] 87 Fed. Reg. at 20111.

NRECA urges EPA to strike daily rates from the final FIP. We have outlined the reasons why this concept is problematic on a practical basis and lacks any legal basis.

The Daily NOx Rate is not achievable based on EPA's own analysis. The daily rate is a one-size-fits-all approach for all coal-fired units that cannot be consistently achieved. EPA recognizes that past data shows that 0.14 lbs./mmBtu can be met on 95% of days during the ozone season.[133] Not only does this acknowledge that EPA has not factored in a typical margin of compliance, but the daily rate is actually not achievable on all days. The rate must be adjusted so that all SCR-controlled units can meet the rate.

NRECA's technical analysis demonstrates that the Daily Rate is not consistently achievable. The daily backstop rate sets up the SCR-equipped coal-fired boiler population to fail. Our technical analysis demonstrates that even units with well-run SCR processes cannot achieve 0.14 lbs./mmBtu, mostly due to unavoidable startup operation. For a detailed analysis of these technical results, please see the Technical Report. We present a summary of findings below.

The Technical Report examines NOx emissions from the SCR-equipped operating fleet in 2021 over the ozone season. The dataset included 110 SCR-equipped EGUs, which emit less than 0.08 lbs./mmBtu. Using past data, the daily NOx emission rate was calculated to determine the feasibility of meeting the daily rate. Only 36 of the 110 units do not experience any operating days emitting above 0.14 lbs./mmBtu. Many units emitted more than 0.14 lbs./mm/Btu for multiple days, and 11 units operated above the daily rate for three days. Five units exceeded that rate for seven days.[134]

Table 7-1[135]

[133] *Id.*
[134] Technical Report at Section 7.2.
[135] Technical Report at Table 7-1.

Rule	Count of Units with Exceedances	Total Exceedances
1-Day Average - with SU/SD Days	74	317
1-Day Average - without SU/SD Days	52	183
2-Day Average - with SU/SD Days	53	149
2-Day Average - without SU/SD Days	22	46
3-Day Average with SU/SD Days	24	62
3-Day Average - without SU/SD Days	9	21

Table 7-1 from the Technical Report illustrates that extending the daily average to a three-day average is not an effective solution. EGU rates above 0.14 lbs./mmBtu decrease but are not eliminated. A three-day averaging period still shows 24 units that have 62 instances in which the daily rate is not achieved.

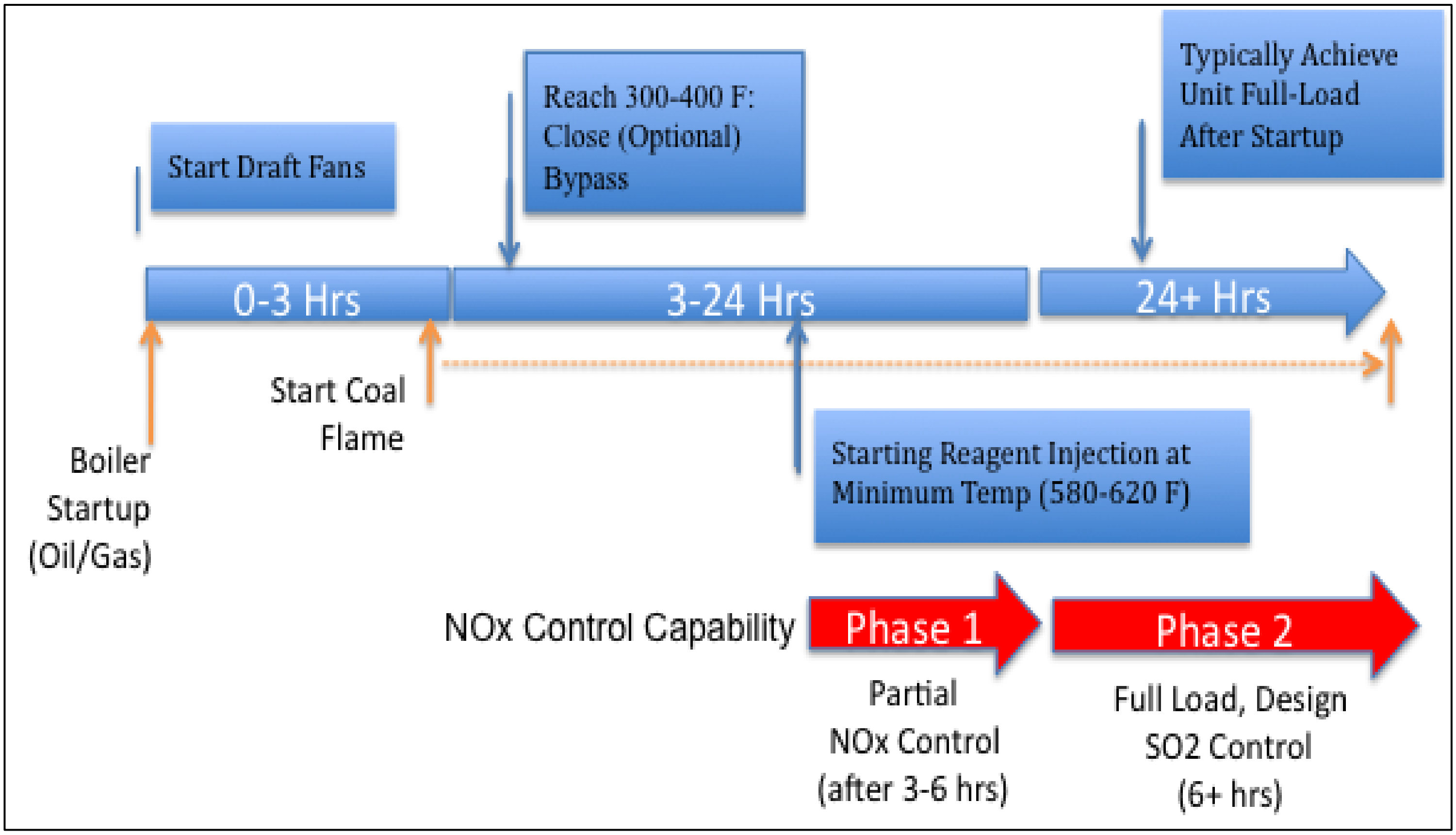
In summary, NRECA's data shows that the daily rate of 0.14 lbs./mmBtu cannot be consistently achieved by a majority of SCR-equipped units.

Unit startups cannot be avoided and must be factored into EPA's analysis. The Proposed FIP ignores how SCR technology works during startup. Startup cannot be avoided. Units must have regular outages for safety and reliability and even the best maintained unit will have equipment failures that force outages.

As presented below, a unit must reach around 580° F for subbituminous coals and 620° F for some bituminous coals before the SCR can function. This key temperature varies based on many factors such as fuel composition and associated sulfur content. Once the SCR reactor reaches the minimum temperature then ammonia reagent can be injected. Post-combustion NOx removal begins but is only at a partial level until the unit comes up to full load. When the unit reaches its design values, the SCR's full NOx removal potential can be realized. NRECA refers to the Technical Report, which outlines this process in more detail, and Figure 7-1.[136]

[136] Technical Report at Section 7.

Figure 7-1. Timeline of Key Events in SCR Process Startup



EPA's use of sulfur dioxide (SO_2) rulemakings as a model for the daily rate is misplaced due to the difference in operation between an flue gas desulfurization (FGD) and SCR.[137] EPA's statement is misinformed: "[S]ome SCR-equipped units have chosen to routinely cycle their emission controls off at lower load levels, such as while operating overnight, instead of operating the controls, upgrading the units to enable the control to be operated under those conditions, or not operating the units under those conditions."[138] SCRs *cannot* operate at low load.

The Daily Rate may actually increase NOx emissions. Some units enjoy the flexibility of operating at low loads, when greater capacity is not needed. Load less than 50% will frequently reduce the boiler outlet gas temperature below the minimum operating temperature for a SCR. Reagent cannot be injected without possible catalyst damage from excess residual ammonia emissions. Applying a Daily Rate will eliminate unit flexibility to run at lower loads – emitting fewer NOx tons. Units will be forced to operate at full load to achieve maximum SCR removal

[137] 87 Fed. Reg. at 20122 n.269-270.
[138] 87 Fed. Reg. at 20111.

rates. More NOx may be emitted overall. Likewise, the Daily Rate decreases flexibility in operating conditions, which may create operational and reliability concerns. Units that can no longer "turn down" to avoid startups. RTOs will see a change in unit behavior that may impact total capacities and unit availability.

The Daily Rate does not take malfunctions into account. The Daily Rate provides no provision for malfunctions of either the boiler – requiring reduction in load – or SCR equipment. We are aware of instances in which ammonia injection equipment failed. We support a bright-line malfunction exception to the Daily Rate.[139]

The Daily Rate compliance dates (2024 or 2027) lack basic fairness. Good actors that have invested in SCRs are rewarded with an early compliance date of 2024, while units without SCR get a pass until 2027. Basic equity should be preserved.

EPA's justification for imposing a Daily Emission Rate fails. EPA justifies the Daily Rate by stating that it will "incentivize improved emissions performance at the individual unit level."[140] EPA returns to its contention that SCR nonoperation is a significant problem on high ozone days. As previously discussed, EPA itself disagreed that data showed a concern in this regard. In the Proposed FIP, EPA identifies two plants as examples;[141] however, we fail to see how two outliers justify imposition of a Daily Rate on an entire sector. Most units do not have the capability to turn off SCRs due to permit conditions.

Daily emission rates are not considered in the FIP's estimated NOx emission reductions for the 2026 attainment case on the downwind monitors. Emission reductions attributable to the daily rate are not folded into EPA's air quality model. Thus, Daily Rates are not an essential part of EPA's strategy to reduce ozone transport. There is no legal basis for an unnecessary requirement when attainment can be achieved based on modeling of the state budgets.

EPA has not properly navigated common stack apportionment for units with dissimilar NOx controls. EPA suggests that simple DAHS reprogramming could achieve accurate common

[139] *See* Technical Report at Section 7.3, discussing the impacts of malfunctions on the daily rate concept.
[140] *Id.*
[141] *Id.*

stack emissions apportionment.[142] We disagree. Any mathematical calculation would have to include individual unit heat rates. Since unit-specific heat rates are variable and often quite different, simple arithmetic cannot substitute for having an actual monitoring device. Unit-specific emissions can only be determined accurately by installation of new continuous emission monitoring systems (CEMS) in the ductwork, and this is not always feasible due to insufficient length of ductwork. Installing a new monitor would serve only to account for unit NOx rate differences from 2024-2026. It is not justifiable on a resource basis to require new monitors for just a three-year time period only during ozone seasons. EPA should exempt SCR common stack units from the daily rate until both units are equipped with SCRs (2027). Other features of the Proposed Rule provide sufficient assurances that the SCR-equipped common stack units will operate during the gap period. If EPA continues with its current proposal, the cost of installation and purchase of new monitoring devices must be added to the costs contemplated by the Proposed Rule.

Conclusion: NRECA supports eliminating the daily backstop rate from the Proposed Rule for the reasons identified above. Putting aside our view of the lack of the necessity of a Daily Rate in general, we have not found a feasible alternative to suggest to EPA that will account for startups, malfunctions, low load needs, and variability among units, fuels, and capacities. We observe that, if a rate were to be adopted, it would need to exclude startup and malfunction events or otherwise provide unit flexibility during these times. In summary, a uniform daily rate is not a fit for all coal-fired unit types and applications.

XII. EPA's Options for States to Depart from the FIP are unlawfully limited.

EPA tied states' hands to address their good neighbor obligations prior to the FIP, as discussed in Section V. EPA pursues the same strategy on the back end. Specifically, EPA has not provided a meaningful opportunity for states to exit the CSAPR-FIP process by proposing a flexible off-ramp option. In so doing, EPA unlawfully commandeers state discretion to address good neighbor obligations, departing from the statutory framework Congress has set.

[142] 87 Fed. Reg. at 20132 ("For units exhausting to common stacks, 40 CFR part 75 includes options that often allow monitoring to be conducted at the common stack on a combined basis for all units as an alternative to installing separate monitoring systems for the individual units in the ductwork leading to the common stack.").

EPA constrains states that chose to submit non-CSAPR SIP Revisions[143] to a standard of "whether strategies as a whole provide adequate and enforceable provisions ensuring that the necessary emissions reductions (i.e., reductions equal to or greater than what the Group 3 trading program will achieve) will be achieved" by the state sources.[144] States are limited to the bar that EPA has set in this rulemaking – which has multiple flaws in datasets, modeling, and propounds the most stringent EGU NOx budgets of all time. EPA unlawfully narrows the avenues in which states may propose.

With the Proposed Rule's aggressive timeline, there is no real opportunity to replace the FIP prior to the start of the program. A Final Rule is anticipated by the end of this year. This rushed rulemaking, again, ignores and minimizes states' roles in this process. An appropriate remedy is state engagement. States should be allowed to submit or re-submit SIPs addressing good neighbor obligations once EPA corrects problems in its datasets and model. If EPA declines this suggestion, then states, at a minimum, should not be held to the standard and requirements articulated by this flawed rulemaking.

XIII. **Conclusion.**

NRECA appreciates EPA's consideration of its comments on the Proposed FIP. This rulemaking is of great importance to our members. We look forward to further engagement with EPA on these points.

[143] If states participate in the CSAPR program per the FIP, then their SIP optionality is virtually eliminated by operation of law. *See* 40 CFR 52.38(a) (enumerating limitations on CSAPR SIPs). Therefore, non-CSAPR SIP revisions are states' only real option as a true off-road from this FIP for EGUs.
[144] 87 Fed. Reg. at 20151.