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November 22, 2024

VIA ELECTRONIC MAIL (daq.publiccomments@deq.nc.gov**)**

Mr. Joseph Voelker, PE
NC DEQ
Division of Air Quality
1641 Mail Service Center
Raleigh, NC 27699-1641

RE: Comments on Draft Permit No. 03676T61 for Duke Energy's Marshall Steam Station (Facility ID No. 1800073)

Dear Mr. Voelker,

The North Carolina Division of Air Quality ("DAQ") has solicited public comments on a draft permit modification ("Draft Permit") for the Marshall Steam Station ("Marshall facility"), which is located within the Marshall Energy Complex in Catawba County, North Carolina. The Draft Permit proposes to authorize Duke Energy Carolinas LLC ("Duke Energy," "Duke," or the "Company") to construct two simple-cycle combustion turbines, fueled by natural gas and No. 2 fuel oil, as well as supporting equipment—including an auxiliary boiler, an emergency generator, and two dew point heaters—at a different location within the Marshall Energy Complex. The Southern Environmental Law Center, Appalachian Voices, CleanAIRE NC, Environmental Defense Fund, National Parks Conservation Association, Natural Resources Defense Council, North Carolina Conservation Network, Sierra Club, and the Southern Alliance for Clean Energy ("Commenters") respectfully submit the following comments detailing our serious concerns with the Draft Permit. Specifically, the Draft Permit unlawfully fails to require Duke Energy to comply with the Clean Air Act's Prevention of Significant Deterioration (PSD) requirements, is

based on inadequate information, and lacks sufficient testing and monitoring requirements to ensure compliance with the Clean Air Act.

INTRODUCTION

The Proposed Modification

According to Duke Energy's application for this permit modification ("Application"), the company plans to retire two of the Marshall facility's existing coal-fired boilers after constructing two new simple-cycle combustion turbines and supporting equipment ("new gas plant").[1] The existing coal-fired power plant at the Marshall facility consists of four electric utility boilers that are fueled primary by coal, but are also permitted to use natural gas and No. 2 fuel oil ("existing coal plant").[2] In 2018, Duke Energy obtained a permit modification authorizing construction of three new heaters in order to support co-firing the existing units with natural gas.[3] The four units' combustion of coal generates fly ash, which is stored on-site in silos and an ash dome pending shipment offsite or disposal in an on-site landfill.[4]

Duke Energy's application seeks authorization to construct two simple-cycle combustion turbines that will be fueled by natural gas and No. 2 fuel oil.[5] The Application describes both new turbines as "non-base load units."[6] However, it does not disclose the specific capacity or selected manufacturer of either turbine. And although Duke Energy characterizes the proposed turbines as being "hydrogen capable," the Application specifies that it "is not requesting authorization to combust hydrogen at this time."[7]

In addition to the new combustion turbines, Duke Energy proposes constructing a new auxiliary boiler (fueled by natural gas and diesel[8]), an emergency generator (fueled by diesel), an emergency firewater pump engine (fueled by diesel), two dew point heaters (fueled by natural gas), and two diesel fuel storage tanks.[9]

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[1] *See* Duke Energy Carolinas, LLC, *Minor NSR Permit Application – Marshall Combustion Turbines Project* (March 2024) ("Application") at 1-1, 2-4.
[2] *Id.* at 2-4.
[3] *Id.*
[4] *Id.*
[5] *Id.*
[6] *Id.* at 4-9.
[7] *Id.* at 2-4.
[8] *Id.* at 4-4.
[9] *Id.* at 2-4.

Prevention of Significant Deterioration

The Clean Air Act's Prevention of Significant Deterioration (PSD) program requires permit applicants constructing new major sources or proposing major modifications to existing major sources to determine and apply the "best available control technology" (BACT) and perform air modeling to confirm that the additional emissions will not cause or contribute to an exceedance of any of the National Ambient Air Quality Standards (NAAQS).[10] A new "[f]ossil fuel-fired steam electric plant" is "major" and therefore subject to PSD permitting and control requirements if it has a potential to emit 100 tons per year (tpy) or more of any regulated PSD pollutant."[11] A physical or operational change to an existing major stationary source is a "major modification" if the increase in emissions attributable to the modification exceeds any regulated PSD pollutant's "significant emissions rate" threshold.[12]

The new gas plant's potential emissions of nitrogen oxides (NO_X), total particulate matter (PM), sulfur dioxide (SO_2), and carbon monoxide (CO) all exceed the 100 tpy major source threshold for PSD applicability for a new fossil fuel-fired steam electric plant.[13] However, Duke claims that the new gas plant is not a new source but is instead a modification to the existing coal plant that the new gas plant purportedly will replace. Thus, Duke asserts that the new gas plant triggers PSD only if the resulting emissions increase exceeds the significant emissions rate for a regulated PSD pollutant.

Even if classified as a modification, the potential emissions from the new combustion turbines and other new units will greatly exceed the applicable significant emissions rate for almost every regulated PSD pollutant.[14] However, Duke Energy claims that construction and operation of the new gas plant does not constitute a major modification and thus "does not trigger PSD review."[15] In order to make this argument, Duke contends that the construction of the new gas plant and the shutdown of two of the units at the existing coal plant qualify as a single "project" under the federal PSD regulations as amended by the "Project Emissions

[10] 42 U.S.C. § 7475(a)(3); 40 C.F.R.§ 51.166(k)(1).
[11] 40 C.F.R. § 51.166(b)(1)(i)(A) (2019) (incorporated by reference in 15A NCAC 2D.0530(b)).
[12] *See* 40 C.F.R. 51.166(b)(2)(i), (b)(23), (b)(39), (b)(49) (incorporated by reference in 15 NCAC 2D.0530(b)).
[13] *See* Application at 3-8 (Table 3-1).
[14] In particular, the new units' potential emissions of NO_X, total PM, PM_{10}, $PM_{2.5}$, SO_2, VOC, CO, H_2SO_4, and CO_2e each exceed their respective SER. *See* Application at A-11.
[15] Application at A-1, n.5.

Accounting" rule promulgated by EPA in 2020.[16] Thus, in determining PSD applicability, Duke Energy subtracts the baseline emissions from coal-fired Units 1 and 2 from the new gas plant's potential emissions, presuming that future emissions from the coal units will be zero[17]—despite proposing to continue operating Units 1 and 2 for some period of time after the new gas plant comes online, until the new plant is "deemed commercially available."[18]

In addition, Duke Energy requests for the permit to include "PSD avoidance limits" for NO_X, CO, and volatile organic compounds (VOC)—purportedly for purposes of "operational flexibility."[19] In its description of this request, Duke Energy admits that the estimates it relied upon for the PSD applicability analysis may significantly underestimate future emissions from the new gas plant. In particular, the company acknowledges that "the NO_X, CO, and VOC emissions controls may not perform optimally under certain operating scenarios."[20] In spite of this admission, Duke Energy specifically requests that the potential emissions from the new auxiliary boiler, emergency engines, dew point heaters, and fuel storage tanks be "subtracted" from the facility-wide PSD avoidance limits calculated in the Application, so that the permit only imposes enforceable limits on the new turbines and coal-fired Units 1 and 2.[21]

The Draft Permit establishes PSD avoidance limits for NO_X, CO, and VOC exactly as proposed by Duke Energy—applicable only as to the "combined emissions from" Unit 1, Unit 2, and the two new combustion turbines.[22] In addition, the Draft Permit imposes a PSD avoidance limit, applicable to the same set of units, for total PM.[23] The Draft Permit does not impose PSD avoidance limits for the other new units, nor does it establish adequate monitoring requirements for those units for purposes of tracking compliance with the facility-wide PSD avoidance values set forth in the Application.

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[16] Prevention of Significant Deterioration (PSD) and Nonattainment New Source Review (NNSR): Project Emissions Accounting (Final Rule), 85 Fed. Reg. 74,890 (Nov. 24, 2020).
[17] *See* Application at A-1.
[18] Application at 2-5.
[19] Application at A-1, n.5.
[20] *Id.*
[21] *Id.*
[22] N.C. Dep't of Env't Quality, Div. of Air Quality, Draft Permit No. 03676T61 (Oct. 16, 2024) ("Draft Permit") at 83 (Condition 2.2 C.1.a).
[23] *Id.*

Environmental Justice

Duke Energy's Application includes an EJScreen report for a five-mile radius around the Marshall Energy Complex, which shows that the surrounding population is in the 55th percentile nationally for cancer risk due to air toxics and the 53rd percentile state-wide for respiratory health impacts due to air toxics.[24] However, DAQ did "not review" this information because it is "not required by statute or regulation."[25]

I. DAQ Must Require the New Gas Plant to Comply with PSD Requirements.

A. The New Gas Plant is a New Major Stationary Source, Not a "Modification" of the Existing Coal Plant.

Contrary to the approach taken by DAQ in preparing the Draft Permit, the new gas plant constitutes a new major stationary source, not a modification to the existing coal plant. Accordingly, Duke cannot lawfully evade PSD requirements for the new gas plant by subtracting the emission decreases anticipated from the eventual shutdown of Units 1 and 2 from the new gas plant's emissions. When properly evaluated as a new stationary source, the new gas plant's potential emissions of NO_X, total PM, SO_2, and CO indisputably exceed the applicable PSD major source threshold of 100 tpy.[26]

The Clean Air Act defines a "modification" for purposes of PSD applicability as "any *physical change in, or change in the method of operation of, a stationary source* which increases the amount of any air pollutant emitted by such source or which results in the emission of any air pollutant not previously emitted."[27] As confirmed by federal regulations, the "stationary source" that is being changed must be an "*existing* major stationary source."[28]

Here, the "existing major stationary source" at issue is two of the units at Duke's existing coal plant. The new gas plant does not physically change either of these units nor does it change their method of operation. Rather, Duke states that it will construct the two new gas-fired combustion turbines "as replacements for coal-fired Units 1 and 2."[29] In other words, Duke will retire two existing coal-fired units and construct new, separate units that use a different fuel for

[24] Application, Appendix F – EJScreen Community Report at 2.
[25] N.C. Dep't of Env't Quality, N.C. Div. of Air Quality, *Application Review* (Oct. 16, 2024) ("Application Review") at 33.
[26] *See* Application at 3-8 (Table 3-1).
[27] 42 U.S.C. § 7411(a)(4) (2023) (emphasis added).
[28] 40 C.F.R § 51.166(b)(51) (2019) (emphasis added) (incorporated by reference at 15A NCAC 2D.0530(b)).
[29] Application at 1-1.

power generation. That is, Duke is not seeking approval to upgrade or "repower" the two coal-fired units at the Marshall facility to burn gas; it is planning to build a completely new gas plant. Construction of the new gas plant thus cannot be characterized as a modification of the existing coal plant. In fact, because the new gas plant is designed to operate independently from the existing coal plant, there is no reason why the new gas plant could not be constructed and operated at an entirely different location from the existing coal plant. Duke's decision to locate the new gas plant near the site of the existing coal plant that it plans to retire does not change the reality that the new gas plant is an entirely new major stationary source that must be subject to PSD preconstruction requirements.

Allowing a permit applicant to avoid Clean Air Act PSD preconstruction requirements for a new major stationary source simply by constructing that new source at the site of a retiring existing source and calling the new source a "modification" of the retiring source is entirely at odds with Congressional intent. Under the Act, "[n]o major emitting facility" may be constructed after August 7, 1977, without installing the "best available control technology" and demonstrating that its emissions will not cause or contribute to a violation of any NAAQS or cause air quality to significantly deteriorate.[30] In this way, Congress sought to, among other things:

- "protect public health and welfare" from the adverse impact of air pollution, "notwithstanding attainment and maintenance of all national ambient air quality standards";
- "preserve, protect, and enhance the air quality in national parks, national wilderness areas, national monuments, national seashores, and other areas of special national or regional natural, recreational, scenic, or historic value";
- assure that emissions from a source in one state will not interfere with another state's efforts to prevent significant air quality deterioration.[31]

The *only* stationary sources emitting above the major source threshold that Congress chose to exempt from PSD requirements were older plants (constructed prior to August 7, 1977) thought to be on the verge of retirement—such as the coal-fired Marshall facility. But Congress did not grant those existing sources "perpetual immunity" from PSD requirements.[30] Rather,

[30] *See* 42 U.S.C. § 7475(a)(3).
[31] *See* 42 U.S.C. § 7470 (2023).

Congress specified that existing major stationary sources must comply with PSD when they undertake a "modification" that increases the source's emissions. The idea was to ensure that these initially-exempted major sources install modern pollution controls when it makes sense to do so—specifically, at the time of new or modified construction.[31]

In issuing federal regulations to implement the Act, EPA differentiated between mere "[r]outine maintenance, repair, and replacement," which it exempted from the definition of "major modification"[32] and "life extension project[s]" that restore a deteriorating plant's lost generating capacity as an alternative to replacing it with a new plant that employs modern control technologies.[33] Over the last two decades, EPA as well as members of the public (through citizen suits) have sought to hold sources accountable for undertaking such life-extension projects without complying with PSD requirements.[34]

The longstanding debate over what source changes are "routine" versus which are unusual "life-extension" projects for purposes of determining PSD applicability seems absurd in the face of DAQ's proposal to allow Duke to replace half of its existing coal plant with its new gas plant without undergoing PSD permitting. Obviously, if a company can replace an old plant and avoid PSD when doing so, then it can maintain perpetual immunity from PSD requirements. Literally, forever. While it might be argued that such perpetual immunity is acceptable so long as the new plant emits only slightly more than the existing plant, such argument ignores not only the Act's plain language but also the PSD program's purposes. Congress didn't enact the PSD program just to maintain the status quo; PSD aims to ensure that every new major stationary source reduces its emissions to the level achievable through the use of best available control technology (BACT), and also to ensure that if the source emits up to its maximum allowable emissions, those emissions will not cause or contribute to a NAAQS violation or significantly deteriorate air quality.[35]

Duke's existing coal plant is not required to utilize BACT and has never been required to comply with the PSD requirement that it model the impact of its source-wide emissions and demonstrate that it would not cause or contribute to a NAAQS violation or significantly

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[32] *See* 40 C.F.R. § 51.166(b)(2)(iii)(a) (2019) (defining "Major modification").
[33] *Wis. Elec. Power v. Reilly*, 893 F.2d 901, 911 (7th Cir. 1990).
[34] *See, e.g., U.S. v. Ohio Edison Co.*, 276 F. Supp. 2d 829 (S.D. Ohio 2003); *U.S. v. Southern Indiana Gas & Elec. Co.*, 245 F. Supp. 2d 994 (S.D. Ind. 2003); *U.S. v. Ameren Missouri*, 229 F. Supp. 3d 906 (E.D. Mo. 2017); *U.S. v. East Kentucky Power Coop.*, 498 F. Supp. 2d 976 (E.D. Ky. 2007).
[35] 42 U.S.C. § 7475(a)(3)-(4).

deteriorate air quality. If DAQ finalizes this Draft Permit as written, the new gas plant likewise will not reduce its emissions to the level achievable with modern pollution controls and will not have to assess its impact on ambient air quality. And apparently, the same would be true for the next power plant constructed within the Marshall Energy Complex when the new gas plant reaches the end of its useful life, and so forth and so on. Allowing such perpetual exemption from PSD requirements would contravene the plain language of the statute and regulations and the PSD program's fundamental purposes.[36]

Where, as here, half of an existing major stationary source is being retired, DAQ must not interpret PSD as allowing an entirely new replacement source to be evaluated as a "modification" to the retiring source. Under such circumstances, the new source must be evaluated for PSD applicability based solely on the amount of the new source's potential emissions. Duke's new gas plant will have the potential to emit NO_X, total PM, SO_2, and CO in amounts that exceed the major source threshold.[37] Accordingly, DAQ must require Duke to comply with PSD permitting and control requirements.

B. Even if the New Gas Plant Could be Viewed as Modification to the Existing Coal Plant, the Proposed Construction is a Major Modification Triggering PSD Review.

As explained above, Commenters strongly disagree with Duke's contention that the new gas plant constitutes a modification to its existing coal plant. Even if DAQ treats the new gas plant as a modification, however, DAQ cannot allow Duke to avoid PSD by subtracting the existing coal plant's emissions from the new gas plant's emissions.

i. Background on PSD Applicability Rules for Determining Whether PSD Applies to a Modification to a Major Stationary Source.

EPA's regulations interpret the statutory definition of "modification" to require PSD for a physical or operational change that increases a source's emissions above the applicable significant emissions rate both when the change is considered alone, and when the change is considered in combination with the emission impacts of all other "contemporaneous" and "creditable" changes at the source.[38] Throughout the PSD program's history, EPA has instructed

[36] 42 U.S.C. § 7475.
[37] *See* Application at 3-8 (Table 3-1).
[38] 40 C.F.R. § 52.166(b)(3)(i) (2024).

sources and regulators to make that emissions increase determination using a two-step process, which it memorialized in its PSD regulations in 2002.[39]

Under the two-step process, a source must first determine "[t]he increase in emissions from a particular change or change in the method of operation at a stationary source" (Step 1).[40] If the increase determined under Step 1 would exceed the significant emissions rate for any PSD-regulated pollutant, then the regulations instruct the source to determine whether the change would result in a "significant net emissions increase" at the source.[41] "Net emissions increase" is defined to mean the sum of the emissions increase from the change (calculated under Step 1) and "[a]ny other increases or decreases in actual emissions at the major stationary source that are contemporaneous with the particular change and are otherwise creditable" (Step 2).[42] To be "creditable," a contemporaneous emission decreases must be, among other things, "enforceable as a practical matter at and after the time that actual construction on the particular change begins."[43]

Prior to 2020, EPA had long held that (as plainly stated in its regulations) under the two-step analysis, an emission *decrease* can be considered only at Step 2, regardless of whether the decrease results from the physical or operational change under consideration. EPA's pre-2020 position is memorialized in EPA's 1990 New Source Review Workshop Manual (the "1990 NSR Manual"),[44] which declares: "Emission decreases associated with a proposed project (such as a boiler replacement) are contemporaneous and may be considered along with other contemporaneous emissions changes at the source. However, they are not considered at [Step 1] in the analysis."[45] The 1990 NSR Manual further emphasizes that "[i]t is important to note that when *any* emissions decrease is claimed (including those associated with the proposed modification), *all* source-wide creditable and contemporaneous emissions increases and decreases of the pollutant subject to netting must be included" in the NSR applicability determination.[46] EPA reaffirmed that its current regulations do not permit consideration of

[39] 67 Fed. Reg. 80,186, 80,190 (Dec. 31, 2002).
[40] 40 C.F.R. § 52.166(b)(3)(i) (2024).
[41] 40 C.F.R. § 52.166(a)(7)(iv)(A) (2024).
[42] 40 C.F.R. § 52.166(b)(3)(i) (2024). *See also* 45 Fed. Reg. 52,676, 52,698 (Aug. 7, 1980).
[43] 40 C.F.R. § 52.166(b)(3)(vi) (2024).
[44] EPA, New Source Review Workshop Manual, Prevention of Significant Deterioration and Nonattainment Area Permitting (Draft, Oct. 1990), https://www.epa.gov/sites/production/files/2015-07/documents/1990wman.pdf (Attachment 1).
[45] *Id.* at A.46.
[46] *Id.* at A.36 (emphasis in original).

decreases at Step 1 in a lengthy analysis provided in response to a PSD permit application from HOVENSA.[47] EPA confirmed, therein, that the amendments made in its 2002 NSR Reform Rule did not alter "the historic two step NSR applicability test."[48]

In 2020, EPA finalized the "Project Emissions Accounting" rule, which fundamentally changed the nature of the two-step PSD applicability analysis by allowing permit applicants to take credit for emission decreases associated with an entire "project"—broadly interpreted—under Step 1.[49] The term "project" is defined in the revised federal PSD regulations as "a physical change in, or change in the method of operation of, an existing major stationary source."[50] Pursuant to the 2020 Project Emissions Accounting Rule, project-related emission decreases considered at Step 1 of the PSD applicability analysis do not need to meet the same criteria as decreases counted under Step 2. Specifically, unlike Step 2 decreases, Step 1 decreases do not need to be "contemporaneous" with the project-related emissions increases they are used to offset, meaning that they do not need to occur during a reasonable period "before the date that the increase from the particular change occurs."[51] In addition, Step 1 decreases are not subject to the Step 2 requirement that they be "creditable" (including that the decreases be "enforceable as a practical matter at or after the time that actual construction on the particular change begins").[52] Commenters believe that the Project Emissions Accounting rule violates the text and purpose of the Clean Air Act. A petition for review of the rule is pending before the U.S. Court of Appeals for the D.C. Circuit.[53]

While EPA's 2020 Project Emissions Accounting Rule revised the federal PSD regulations, it is up to each State to decide whether to revise its Clean Air Act State Implementation Plan ("plan") to incorporate Project Emissions Accounting. Notably, North Carolina did not amend its state regulations governing PSD applicability and has not otherwise

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[47] *See* Letter from Barbara A. Finazzo, U.S. EPA Region 2, to Kathleen Antoine, HOVENSA, LLC, RE: HOVENSA Gas Turbine Nitrogen Oxides (GT NO_x) Prevention of Significant Deterioration (PSD) Permit Application-Emission Calculation Clarification (Mar. 30, 2010) (Attachment 2).
[48] *Id.* at 3.
[49] *See generally* 85 Fed. Reg. 74,890.
[50] 40 C.F.R. § 51.166(b)(51) (2024).
[51] 40 C.F.R. § 51.166(b)(3)(ii) (2024).
[52] 40 C.F.R. § 51.166(b)(3)(vi) (2024).
[53] *Envtl. Def. Fund, et al., v. EPA*, No. 18-1149 (D.C. Cir. filed June 18, 2018) (Consolidated with Nos. 21-1033, 21-1039, and 21-1259).

incorporated the federal Project Emissions Accounting Rule into its federally-approved plan.[54] Indeed, the current version of North Carolina's plan expressly provides: "The version of the CFR incorporated in this Rule, with respect to 40 CFR § 51.166, is that as of July 1, 2019 . . . *and does not include any subsequent amendments or edition*."[55]

ii. Duke Cannot Count Emission Decreases Anticipated from Retirement of the Existing Coal Plant as Step 1 of the PSD Applicability Analysis Because North Carolina Has Not Revised its State Implementation Plan to Incorporate Project Emissions Accounting.

Duke asserts that the retirement of coal-fired Units 1 and 2 is part of the same "project" as the construction of its new gas plant.[56] Accordingly, Duke contends that it can count the anticipated decrease in emissions from retiring Units 1 and 2 at Step 1 of the PSD applicability analysis when determining whether the "project" will cause a significant emissions increase.[57] However, as explained above, North Carolina's State Implementation Plan incorporates the 2019 version of the federal PSD rules, which pre-dates the Project Emissions Accounting Rule. The 2019 version of the federal rules does not allow for aggregation of separate modifications into a single "project," and it does not allow for an emissions increase attributable to one "particular change" to be offset by a decrease in emissions attributable to another "particular change" under Step 1 of the PSD applicability analysis. Instead, such emissions reductions may only be used for netting purposes under Step 2—where they must meet specific criteria such as being contemporaneous and otherwise creditable.

To the extent that DAQ may believe that it may simply interpret the 2019 version of the federal rule to allow for emission decreases to be netted out at Step 1, Commenters note that such

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[54] The current version of North Carolina's federally-approved PSD regulations, which are codified at 15A NCAC 2D.0530, are available at https://www.epa.gov/system/files/documents/2024-05/02d.0500-clean.pdf. As shown on page 32, the last time North Carolina submitted an updated version of 15A NCAC 2D.0530 to EPA for incorporation into its State Implementation Plan was on April 23, 2021. EPA approved this submission on January 5, 2023. *See Air Plan Approval; NC; Miscellaneous NSR Revisions and Updates; Updates to References to Appendix W Modeling Guideline (Final Rule)*, 88 Fed. Reg. 773, (Jan. 5, 2023). The preamble to EPA's approval of the submission specifies that the version of 15A NCAC 2D.0530 being incorporated into the State Implementation Plan went into effect under state law on October 1, 2020. *See id.* at 773–774. This pre-dated EPA's adoption of the PEA rule, which went into effect on December 24, 2020. *See* 85 Fed. Reg. 74,890.

[55] 15A NCAC 2D.0530(v) (emphasis added).

[56] *See, e.g.*, Application at 1-1, 3-5.

[57] *See, e.g.*, Application at 3-5 ("[Duke] set the [projected actual emissions] to zero for Units 1 and 2 because they will be shut down as part of the Project.").

an interpretation is wholly inconsistent with the plain language of the regulation and would therefore be arbitrary and capricious.

On its face, the rule expressly limits the analysis under Step 1 to consideration of an "increase" in emissions that is attributable to the proposed modification—whereas the analysis under Step 2 allows for the consideration of a "net emissions increase" that takes into account "other increases and decreases" that are attributable to other changes at the facility.[58] The rule's definition of a "net emissions increase" further clarifies the limited scope of the Step 1 analysis by specifying that "the increase" considered at that initial step must be attributable to "a *particular* physical change or change in the method of operation"[59]—whereas the "other increases and decreases" that can be netted out at Step 2 are those attributable to other changes at the facility that are "contemporaneous with the *particular* change" considered at Step 1.[60] Because the language of the rule discussing Step 1 refers only to an "increase" and the language discussing Step 2 expressly incorporates both "increases *and decreases*," well-established canons of interpretation dictate that any decreases may not be taken into account at Step 1.[61]

EPA's 2020 Project Emissions Accounting Rule fundamentally altered the application of this plain language in 40 CFR § 51.166 by amending the provision that applies the two-step analysis to "projects that involve multiple types of emissions units." In particular, EPA amended 40 CFR § 51.166(a)(7)(iv)(f) and added a new subsection, § 51.166(a)(7)(iv)(g). The latter provision expressly allows for the "sum of the difference"—as used in the former provision—to "include both increases *and decreases* in emissions."[62] Importantly, this provision does not appear in the 2019 version of the rule that is incorporated by reference into chapter 15A, subchapter 2D.0530 and North Carolina's State Implementation Plan.[63] As a result, based on the plain language of the 2019 version of the rule, Duke cannot include emission decreases

[58] 40 CFR §§ 51.166(a)(7)(iv)(A), (b)(3)(i)(B) (2019).
[59] *Id.* at § 51.166(b)(3)(i)(A).
[60] *Id.* at § 51.166(b)(3)(i)(B).
[61] *See RadLAX Gateway Hotel v. Amalgamated Bank,* 566 U.S. 639, 644–45 (2012) (noting that a "well established canon of statutory interpretation" forbids reading by which "[one] clause … permits precisely what [an adjacent] clause … proscribes").
[62] 40 CFR § 51.166(a)(7)(iv)(g) (2024).
[63] 15A NCAC 2D.0530.

anticipated from retirement of coal-fired Units 1 and 2 in its Step 1 determination as to whether its new gas plant will produce a significant emissions increase.[64]

To the extent that DAQ may believe that EPA's adoption of the Project Emissions Accounting Rule in December 2020 had the effect of automatically changing the rules that apply under North Carolina's State Implementation Plan, Commenters note that such an interpretation would be wholly inconsistent with case law addressing that very point. The only way for plan-approved rules to be updated is through the formal plan amendment process.[65] EPA simply cannot unilaterally amend the rules that have been incorporated into a state's plan, whether by informal interpretation or formal rulemaking.[66]

iii. Even if North Carolina's State Implementation Plan Can Be Interpreted as Allowing Project Emissions Accounting, the Existing Coal Plant Emission Decreases Cannot be Considered Under Step 1 of the PSD Applicability Analysis Because Retirement of Units 1 and 2 is not Part of the Same "Project" as Construction of the New Gas Plant.

Even if the new gas plant can be considered part of the same source as the existing coal plant, the closure of Units 1 and 2 cannot be considered part of the same "project" as the proposed new gas plant for Step 1 purposes. In EPA's 2020 Project Emissions Accounting Rule, EPA explained that for multiple changes to be considered part of the same project, these changes need to be "substantially related" as defined in EPA's 2018 project aggregation action.[67] Specifically, to be "substantially related," there must be "an apparent technical or economical

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[64] Indeed, when EPA promulgated the version of the PSD applicability rule that was in effect in 2019, the agency confirmed that the rule language was not intended to allow for decreases in emissions to be considered at Step 1. *See* Prevention of Significant Deterioration (PSD) and Nonattainment New Source Review (NSR): Baseline Emissions Determination, Actual-to-Future-Actual Methodology, Plantwide Applicability limitations, Clean Units, Pollution Control Projects (Final Rule), 67 Fed. Reg. 80,186, 80,190 (Dec. 31, 2002) (explaining that the revision to "the definition of major modification" merely "clarif[ied] what has always been our policy—that determining whether a major modification is a two-step process"); *id.* at 80,197 ("If your calculations show that a significant emissions increase will result from a modification, you have the option of taking into consideration any contemporaneous emissions changes that may enable you to net out of review," and "[t]he contemporaneous time period will not change").

[65] *See* 42 U.S.C. § 7410(i) (2023) (EPA cannot "modify[] any requirement of an applicable implementation plan … with respect to any stationary source" other than via specifically identified mechanisms).

[66] *See, e.g.*, *Sierra Club v. Tenn. Valley Auth.*, 430 F.3d 1337, 1346–48 (11th Cir. 2005) (stating that EPA may not "unilaterally revise [state implementation plans] without submitting the revision to the rigors of the [State Implementation Plan] amendment process"); *Sierra Club v. Georgia Power,* 443 F.3d 1346, 1354 (11th Cir. 2006) ("Even if the EPA had intended its [policy statement] to alter the meaning of Georgia's existing [State Implementation Plan] and similar provisions in other states' [State Implementation Plans], the EPA would have been powerless to effect such a change absent a formal [State Implementation Plan] revision.").

[67] 85 Fed. Reg. 74,890, 74,895, 74,898 n.73.

interconnection between the physical and operational changes."[68] Here, Duke's promised shutdown of Units 1 and 2 is neither technically nor economically interconnected with construction of the new gas plant. Obviously, the existing coal plant does not need the new gas plant to operate. Likewise, the new gas plant will do nothing to make the existing coal plant economically viable and vice versa. In fact, there is no reason Duke couldn't construct its proposed gas units at a completely different location.

C. The New Gas Plant Will Result in a Significant Emissions Increase.

Duke Energy's own estimates for potential emissions from the new gas plant confirm that the project will result in a significant increase in emissions of 8 regulated PSD pollutants:

	Potential Annual Emissions Rate (tpy)[69]							
New Emission Unit	**NO_X**	**Total PM**	**PM_{10}**	**$PM_{2.5}$**	**SO_2**	**VOC**	**CO**	**H_2SO_4**
Simple Cycle Turbines	383.000	98.500	33.900	29.100	105.000	58.700	293.000	8.060
Auxiliary Boiler	25.700	3.250	0.986	0.246	42.000	0.744	11.400	0.000
Dew Point Heaters	8.760	0.666	0.666	0.666	0.053	0.482	7.360	0.000
Emergency Generator	7.740	0.282	0.282	0.282	0.008	0.422	4.230	0.000
Firewater Pump	0.634	0.037	0.037	0.037	0.001	0.243	0.555	0.000
Diesel Fuel Tanks	0.000	0.000	0.000	0.000	0.000	1.920	0.000	0.000
Total (tpy)	**425.834**	**102.735**	**35.871**	**30.331**	**147.062**	**62.511**	**316.545**	**8.060**
PSD SER (tpy)	40.000	25.000	15.000	10.000	40.000	40.000	100.000	7.000
Amount Over SER (tpy)	385.834	77.735	20.871	20.331	107.062	22.511	216.545	1.060
Percent Over SER	**964.59%**	**310.94%**	**139.14%**	**203.31%**	**267.65%**	56.28%	**216.55%**	15.14%

[68] *Id.*
[69] Application Review at 11 (Table 3).

Notably, the "potential to emit" values shown above likely underestimate the new gas plant's real potential emissions. For example, the Application does not specify the manufacturer Duke Energy has selected to supply the new combustion turbines, depriving DAQ of crucial information needed to evaluate the validity of the company's estimates of potential emissions. Instead, the Application merely suggests that the manufacturer will be General Electric or Siemens by citing to "vendor-provided" emissions factors provided by both companies.[70] DAQ should require Duke Energy to supplement its Application to identify the turbine manufacturer and update the potential emission values accordingly.

In addition, Duke Energy itself admits that the estimates it relied upon for the PSD applicability analysis may significantly underestimate future emissions from the new gas plant. In particular, the company acknowledges that "the NO_X, CO, and VOC emissions controls may not perform optimally under certain operating scenarios."[71]

Even assuming that Duke Energy has not underestimated the new gas plant's potential emissions, the potential emissions calculated by the Company show that under Step 1 of the PSD applicability analysis, the proposed project will result in emissions of 8 regulated pollutants that exceed each respective significant emissions rate threshold. As a result, DAQ should find that the project will result in a significant emissions increase under Step 1 and the PSD analysis should proceed to Step 2.

D. Duke Energy May Not Take Credit for the Emissions Reductions from Retiring Units 1 and 2 Because Those Reductions are Not Contemporaneous or Creditable.

In light of the above arguments, the only possible way for Duke to avoid PSD based on emission decreases anticipated to occur from the retirement of Units 1 and 2 would be to count the decreases at Step 2 (in calculating whether there is a significant *net* emissions increase). However, the coal units' emissions decreases cannot be counted at Step 2 because they fail to meet Step 2 criteria. Specifically, the emission decreases must be both "contemporaneous" and "otherwise creditable."[72] A decrease in emissions is "contemporaneous" only if it occurs within the seven-year period "*before* the date that the emissions increase from the particular change

[70] *See, e.g.*, Application at A-9 n.1, A-10 n.1, A-28.
[71] Application at A-1, n.5.
[72] *See* 40 C.F.R. § 51.166(b)(3)(i)(B).

occurs"[73]—i.e., when the new units begin operation.[74] In addition, a decrease in emissions is "creditable" only if the previous level of either actual or allowable emissions (whichever is lower) exceeds the new level of actual emissions; the decrease is enforceable as a practical matter at and after the time of construction; and the decrease has roughly the same significance for public health and welfare as that attributed to the increase in emissions from the particular change.[75] The Draft Permit's acceptance of Duke Energy's PSD applicability calculations is arbitrary and capricious because the emissions reductions from retiring Units 1 and 2 will not be "contemporaneous" with the increase in emissions from the new gas plant and are also not "otherwise creditable."

Although Condition 2.2 C.1.b requires Duke Energy to shutdown coal-fired Units 1 and 2, it also authorizes these units to continue operating after the new turbines are commercially operational.[76] In particular, Condition 2.2 C.1.b expressly authorizes these coal-fired boilers to operate simultaneously with the new gas turbines throughout their entire shakedown period. And unless the condition is amended as recommended below in Section III, it also authorizes simultaneous operation of the coal and gas units for an unspecified duration "after" the gas units are fully operational.

As a result, the decrease in emissions from retirement of Units 1 and 2 will not, by definition, occur "contemporaneously" with—or within the seven-year period *before*—the increase in emissions from the construction and operation of the new combustion turbines. It is therefore impermissible under North Carolina's State Implementation Plan for Duke Energy to take credit for those emission reductions to offset the potential emissions of the new gas plant at Step 2.

Even if DAQ amends Condition 2.2 C.1.b to include an enforceable timeline for retirement of Units 1 and 2 that specifically requires those units to be fully shutdown within 180

[73] 40 C.F.R. § 51.166(b)(3)(ii) (emphasis added); *see also* 15A NCAC 2D.0530(b)(2) ("In the definition of 'net emissions increase,' the reasonable period specified in 40 CFR 51.166(b)(3)(ii) shall be seven years.").
[74] *See* 40 C.F.R. § 51.166(b)(3)(vii) (2019) ("An increase that results from a physical change at a source occurs when the emissions units on which construction occurred becomes operational and begins to emit a particular pollutant. Any replacement unit that requires shakedown becomes operational only after a reasonable shakedown period, not to exceed 180 days."); *see also* 2D.0530(a) ("The minimum requirements described in the portions of 40 CFR 51.166 are hereby adopted as requirements under this Rule, except as otherwise provided in this Rule.").
[75] *See* 40 C.F.R. §§ 51.166(b)(3)(iii), (vi).
[76] Draft Permit at 83.

days of the beginning of the shakedown period for the new turbines,[77] Duke Energy still cannot show that the decrease in emissions are "otherwise creditable" because the old level of emissions must exceed the new level of actual emissions, and the new emissions must not result in more significant impacts to public health and welfare.[78]

Duke Energy's own analysis shows that the new gas plants' potential emissions of total PM, VOC, lead, and carbon dioxide equivalent (CO_2e) are higher than the coal plant's baseline emissions of those pollutants. Indeed, the potential emissions of VOC, lead, and CO_2e are *significantly* higher:

	PM	**VOC**	**Pb**	**CO_2e**
Baseline Emissions: Units 1 & 2 (tpy)[79]	81.0	30.0	0.0137	2,124,070
Potential Emissions: New Units (tpy)[80]	103.0	63.0	0.0475	5,631,871
Project's Increase in Emissions (tpy)	22.0	33.0	0.0338	3,507,801
Percent Increase Over Baseline	27.16%	**110.00%**	**246.72%**	**165.15%**

Even with the PSD avoidance limits set forth in the Draft Permit, the new gas plant's emissions of total PM and VOC will still be permitted to exceed the coal plant's baseline emissions (and will presumably do so once the coal units are retired, given the potential emission values shown above):

	PM	**VOC**
Baseline Emissions: Units 1 & 2 (tpy)[81]	81.0	30.0
PSD Avoidance Limit (tpy)[82]	101.5	65.6
Project's Increase in Emissions (tpy)	20.5	35.6
Percent Increase Over Baseline	25.31%	**118.67%**

[77] *See* 40 C.F.R. § 51.166(b)(3)(vii) (2019) ("An increase that results from a physical change at a source occurs when the emissions units on which construction occurred becomes operational and begins to emit a particular pollutant. Any replacement unit that requires shakedown becomes operational only after a reasonable shakedown period, *not to exceed 180 days*.") (emphasis added).
[78] *See* 40 C.F.R. § 51.166(b)(3)(vi)(A), (C).
[79] Application at 3-8 (Table 3-1).
[80] *Id.*
[81] *Id.*
[82] Draft Permit at 83 (Condition 2.2 C.1.a).

In addition, Duke Energy cannot show that the new gas plants' emissions will have the same significance for public health as the retiring coal units' emissions because the Application includes no baseline studies on local public health for the areas in the vicinity of the Marshall Energy Complex. Moreover, given the potential increases in emissions of VOC and lead, it would be unreasonable to assume that the new gas plant will have the same or less negative impacts on the health and welfare of the surrounding community. Using Duke's own baseline and potential emissions values:

- The new gas plant will have the potential to emit more than twice the amount of VOC than the existing coal plant. The PSD avoidance limit for VOC would actually permit the new gas plant to emit an even higher amount than this potential-to-emit value.[83] VOC emissions contribute to the formation of smog (or ground-level ozone),[84] exposure to which can cause respiratory distress, inflammation of the airways, and chronic obstructive pulmonary disease.[85]
- The new gas plant will emit more than three times the amount of lead than the existing coal plant. There is no PSD avoidance limit to restrict these potential emissions. Lead exposure can damage kidney function, impact the oxygen carrying capacity of blood, and adversely affect the reproductive, developmental, immune, and nervous systems.[86] Lead exposure is also known to cause neurological effects in children, including behavioral problems and learning deficits.[87]

Based on the Draft Permit's express authorization for simultaneous operation of the existing coal-fired boilers and the new gas turbines, and in light of the potential increase in emissions of total PM, VOC, lead, and CO2e, Duke Energy should not be permitted to take credit for the emissions reductions that will result from retirement of Units 1 and 2 as a means to

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[83] Draft Permit at 83 (Condition 2.2 C.1.a).
[84] *See Technical Overview of Volatile Organic Compounds*, U.S. ENVIRONMENTAL PROTECTION AGENCY, https://www.epa.gov/indoor-air-quality-iaq/technical-overview-volatile-organic-compounds (last updated Mar. 5, 2024).
[85] *See Learn About How Mobile Source Pollution Affects Your Health – Smog and Your Health*, U.S. ENVIRONMENTAL PROTECTION AGENCY, https://www.epa.gov/mobile-source-pollution/learn-about-how-mobile-source-pollution-affects-your-health#smog (last updated Jan. 3, 2024).
[86] *See Basic Information about Lead Air Pollution*, U.S. ENVIRONMENTAL PROTECTION AGENCY, https://www.epa.gov/lead-air-pollution/basic-information-about-lead-air-pollution (last updated June 13, 2024).
[87] *See id.*

evade PSD review for the new gas turbines. DAQ's approval of this bait-and-switch tactic would make a mockery of the Clean Air Act's permitting requirements for major sources, which are intended to ensure that new sources of emissions utilize modern control technology to minimize impacts on local communities—instead of perpetuating the environmental and health impacts of old, dirty facilities and their outdated emissions controls.

II. The Draft Permit Cites the Wrong Date for Receipt of a Complete Application and the Permit Application Fails to Provide Any Justification for Use of an Extended Lookback Period to Calculate Baseline Emissions.

North Carolina's State Implementation Plan rules for construction permits specify the information that must be provided in order for a permit application to be considered complete.[88] Among other things, an application for a modification to an existing facility must include "a zoning consistency determination" that "bears the date of receipt entered by the clerk of the local government" or "consists of a letter from the local government indicating that all zoning or subdivision ordinances are met by the facility."[89] Unless and until this documentation is provided, "the application package shall be considered incomplete for processing."[90]

Although Duke Energy's Application included the company's *request* for a zoning consistency determination, it did not include any documentation "bear[ing] the date of receipt entered by the clerk" as required by 15 NCAC 2Q.0304(b)(1)(A).[91] Indeed, in the email request included in the Application, Duke Energy specifically asked the County official to "sign, title, stamp, and date the enclosed form" and "scan a copy of the form back," in order to demonstrate "proof of transmittal."[92] Because no such dated copy of the form was included in the Application, DAQ was required to consider it "incomplete for processing."[93]

DAQ's Application Review document details the back-and-forth between DAQ and Duke Energy regarding the status of the company's request for a zoning consistency determination. First, on April 24, 2024—nearly a month after Duke Energy submitted the Application—DAQ "asked if they had received anything back on their email request to Catawba County."[94] A Duke Energy representative "wrote back that they have not heard anything regarding the zoning

[88] *See id.* at 2Q.0304, 2Q.0305
[89] *Id.* at 2Q.0304(b)(1).
[90] *Id.* at 2Q.0305(1)(b).
[91] *See* Application, Appendix E – Zoning Consistency Determination Request.
[92] *Id.* at 1.
[93] 15A NCAC 2Q.0305(1)(b).
[94] Application Review at 2.

consistency determination request."[95] More than two months after that, DAQ informed Duke Energy that the agency "will need something on zoning."[96] In response, the Duke Energy representative told DAQ "that she has reached out to the county planning office to inquire about the status of the determination."[97] Almost two months after that, on August 20, 2024, DAQ received a signed zoning consistency determination from Catawba County.[98]

Despite this clear timeline of events set forth in DAQ's Application Review document, the Draft Permit lists the "Complete Application Date" as March 28, 2024—the date of Duke Energy's initial application submission, five months before DAQ received the required documentation regarding the County's zoning consistency determination.

This error in the Draft Permit is not merely administrative, nor is it inconsequential. The date on which DAQ receives a complete permit application determines the scope of historical emissions data that can be used to determine the facility's baseline emissions, which is a critical input for the PSD applicability analysis. In particular, North Carolina's federally-approved rules for PSD applicability[99] provide that "baseline actual emissions" must be calculated using data from a "consecutive 24-month period" that occurs "within the five year period immediately preceding the date that a complete permit application is received by the Division."[100] In other words, the "lookback period" for baseline emissions cannot begin more than five years before Duke Energy's permit application was actually "complete."

In this case, the five-month discrepancy in DAQ's determination of when it received a complete application has a substantial impact on the calculation of baseline emissions for coal-fired Units 1 and 2—which in turn has a substantial impact on the calculation of PSD avoidance limits. Because DAQ did not receive a complete application until the zoning consistency determination was submitted in August of 2024, the earliest date on which the 24-month lookback period could possibly begin would be in September of 2019. However, DAQ's Application Review document clearly identifies that the facility's baseline emissions for NO_X,

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[95] *Id.*
[96] *Id.* at 3.
[97] *Id.*
[98] *Id.*
[99] North Carolina's federally-approved provisions for determining PSD applicability, which are codified at 15A NCAC 2D.0530, were approved by the EPA in 2023. *See* 88 Fed. Reg. 773, 773-775, *Air Plan Approval; NC; Miscellaneous NSR Revisions and Updates; Updates to References to Appendix W Modeling Guideline (Final Rule)* (Jan. 5, 2023).
[100] 15A NCAC 2D.0530(b)(1)(A).

SO_2, and sulfuric acid (H_2SO_4) were calculated using emissions data beginning in April of 2019.[101]

Again, this discrepancy is not inconsequential. Duke Energy's use of earlier emissions data yields inflated baseline emission values up to seven percent higher than they are when using data from the five-year lookback period specified in North Carolina's State Implementation Plan:

Baseline Period Used	**SO_2**	**NO_X**	**H_2SO_4**
April 2019 – March 2024	1,343.0	2,407.0	39.0
September 2019 – August 2024[102]	1,255.0	2,288.0	37.0
Percent Difference	7.0%	5.2%	5.4%

Had the Application actually been complete when Duke Energy initially submitted it on March 28, 2024, the use of historical emissions dating back to April of 2019 would have been permissible. But as a result of the company's failure to timely submit the required documentation regarding zoning, it is not. The only permissible basis to use emissions data predating the five-year lookback period is if the facility demonstrates to DAQ's satisfaction that such earlier data is "more representative of normal source operation."[103] However, neither the Application nor DAQ's Permit Review document includes any such justification for the use of an extended lookback period. Accordingly, DAQ must require Duke Energy to submit a detailed explanation of why emissions data from the spring of 2019 are "more representative" or to submit revised PSD applicability calculations using baseline actual emissions values for NO_X, SO_2, and H_2SO_4 that fall within the five-year lookback period. In the meantime, until such information is provided and deemed adequate, DAQ cannot take final action on this permit.

In addition, the data relied upon by Duke Energy to calculate baseline emissions for condensable PM is of questionable validity and relevance. Although the heat input data used to calculate these emissions was taken from a 24-month period that falls within the default five-year lookback period (June 2020–May 2022),[104] the emissions factor used to calculate the emissions

[101] Application Review at 10 (Table 1).
[102] This 24-month period had the highest average emissions of NO_X, SO_2, and H_2SO_4 within the default five-year lookback period. *See* Application at A-6 (Table A-5, Total Baseline Emissions and Selection of Project Baseline).
[103] 15A NCAC 2D.0530(b)(1)(A).
[104] Application at A-6 (Table A-5).

for both coal-firing and oil-firing in Units 1 and 2 relies upon a stack test that was performed on Unit 2 in 2002.[105] First, there is no explanation for how a single stack test would be representative of emissions for both coal-firing and oil-firing. Second, it is not clear that the stack test performed on Unit 2 would be representative of emissions from Unit 1. Finally, it is doubtful that the 2002 stack test is representative of actual emissions during the selected baseline period, given the significant permit modification issued in 2019 to enable co-firing of natural gas in all the coal-fired boilers, including Units 1 and 2.[106]

III. The Draft Permit's Requirement for Duke Energy to Retire Coal-Fired Units 1 and 2 Needs to Include Enforceable Dates and Durations.

Commenters commend DAQ for including an enforceable condition in the Draft Permit that requires Duke Energy to retire coal-fired Units 1 and 2 once the new gas turbines are commercially operational.[107] Notably, a similar condition was *not* included in the draft permit modification for the Roxboro Steam Generating Plant.[108] The inclusion of Condition 2.2 C.1.b in this Draft Permit confirms that DAQ has not only the regulatory authority but the willingness to ensure that the representations made by permittees in their permit applications and public statements are not merely hollow promises.

Nevertheless, Commenters respectfully request that Condition 2.2 C.1.b be amended to include an enforceable backstop date for the permanent shutdown of Units 1 and 2. In addition, DAQ should establish a maximum duration for the shakedown period,[109] during which Condition 2.2 C.1.b expressly authorizes simultaneous operation of the coal-fired units and the new combustion turbines, as well as a specific deadline after the end of that shakedown period by which Units 1 and 2 must be permanently shut down. DAQ should also specify an enforceable deadline by which Duke Energy must submit an application for a permit modification to delete Units 1 and 2 from the facility's air permit.

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[105] Application at A-4 (Table A-3).
[106] *See* N.C. Dep't of Env't Quality, Div. of Air Quality, Air Quality Permit No. 03676T57, Summary of Changes to Permit, ATTACHMENT (May 3, 2019), https://edocs.deq.nc.gov/AirQuality/DocView.aspx?id=471114&dbid=0&repo=AirQuality (explaining that permit modification "[r]evised emission source description for ES-1 through ES-4 from 'One No. 2 fuel oil/coal-fired utility boiler" to "One No. 2 fuel oil/natural gas/coal-fired electric utility boiler").
[107] Draft Permit at 83 (Condition 2.2 C.1.b).
[108] *See* N.C. Dep't of Env't Quality, Div. of Air Quality, Draft Permit No. 01001T60 (Oct. 10, 2024) at 81 (Roxboro Draft Permit).
[109] This maximum duration for the shakedown period should be no more than 180 calendar days. *See* 40 C.F.R. § 51.166(b)(3)(vii) (2019) (specifying that "a reasonable shakedown period" shall "not to exceed 180 days").

Incorporation of these recommendations would result in the following amended language for Condition 2.2 C.1.b:

> b. The Permittee shall permanently shutdown coal-fired boilers (**ID Nos. ES-1 and ES-2**) within [X] calendar days after commercial operation of the new combustion turbines (**ID Nos. ES-41 and ES-42**) has occurred, or by [date], whichever occurs earlier. Operation of the coal-fired boilers may continue during construction of the new combustion turbines and during their shakedown period, provided that the shakedown period is limited to no more than 180 calendar days. The Permittee shall submit an application to request deletion of the boilers from the permit within [X] weeks of the end of the shakedown period for the new combustion turbines.

The above amendments are necessary to ensure that Duke Energy does not artificially prolong the construction timeline and/or shakedown period for the new combustion turbines as a means to continue operating the coal-fired units for longer than is reasonably necessary. Inclusion of enforceable dates and durations will also better enable DAQ and members of the public to evaluate and determine the status of Duke Energy's compliance with this permit condition, and to take appropriate enforcement action in the event Duke Energy fails to timely retire Units 1 and 2 as it has promised.

IV. The Draft Permit's PSD Avoidance Limits Are Flawed and Incomplete.

Duke Energy's request for PSD avoidance limits effectively acknowledges that it is unlawful for the company to evade PSD review by taking credit for future emission reductions associated with retirement of the coal units despite the fact that those units will operate simultaneously with the new gas turbines for some unspecified period of time.[110] However, Duke Energy only proposed PSD avoidance limits for NO_X, CO, and VOC.[111] As a result, the Company's Application still suffers from the deficiencies identified above regarding the use of netting in the PSD applicability analyses for PM, SO_2, lead, and H_2SO_4.

First, Commenters commend DAQ for establishing a PSD avoidance limit for total PM in the Draft Permit,[112] despite the fact that Duke Energy did not propose such a limit. As with the inclusion of Condition 2.2 C.1.b to require retirement of Units 1 and 2, the inclusion of an enforceable PSD avoidance limit for PM in Condition 2.2 C.1.a confirms that DAQ has not only

[110] *See* Section I, *supra*.
[111] *See* Application at 3-8 (Table 3-1).
[112] *See* Draft Permit at 83 (Condition 2.2 C.1.a).

the regulatory authority but the willingness to impose requirements to help ensure that future operations of facilities at the Marshall Energy Complex do not result in emissions that would have otherwise required a more stringent level of permitting review and lower emission limits.

Nevertheless, the PSD avoidance limits established in Condition 2.2 C.1.a are not sufficient to ensure that facility-wide emissions do not ultimately result in a significant increase over the facility's baseline emissions. In particular, the limits established for NOx, PM, VOC, and CO do not restrict emissions of those pollutants from the other new units for which the Draft Permit would authorize construction. Although the limits set forth in Condition 2.2 C.1.a were calculated by subtracting the total potential emissions from those units,[113] the Draft Permit fails to ensure compliance with certain assumptions used to calculate those units' potential emissions. For example:

- The potential annual emissions for the new diesel fuel storage tanks were calculated based on an assumption that the fuel oil throughout would only be needed to support each new turbine's operation of 500 hours per year.[114] The Draft Permit characterizes these new fuel storage tanks as insignificant activities and thus does not establish any enforceable permit conditions to limit their emissions.[115]
- The potential annual emissions from the two new emergency engines were calculated based on an assumption that they will each operate for no more than 500 hours per year.[116] The Draft Permit characterizes the emergency firewater pump engine as an insignificant activity and thus does not establish any enforceable permit conditions to limit its operation or emissions.[117] And although the Draft Permit establishes an operational limit for the new emergency generator of 100 hours per year for purposes of "maintenance checks and readiness testing,"[118] it specifically provides that "[t]here is no time limit on the use of emergency stationary ICE in emergency situations."[119] While it would not be appropriate to limit the hours of operation of this generator in emergency situations, the permit could impose a PSD avoidance limit on the combined emissions

[113] *See* Application Review at 10 n.5 ("the [potential-to-emit] of the new auxiliary equipment (engines, heaters, tanks, auxiliary boiler) has been subtracted from the proposed PSD avoidance limits.").
[114] Application Review at 9.
[115] Draft Permit at 95.
[116] Application Review at 8.
[117] Draft Permit at 95.
[118] Draft Permit at 53 (Condition 2.1 O.2.j.ii.A.).
[119] Draft Permit at 53 (Condition 2.1 O.2.j.i.).

from all of the new auxiliary units such that increased operation of the emergency generator could be offset by reduced operation of the other units as needed to prevent a significant increase in emissions.

In addition, for all the new units, Duke Energy's calculations of potential emissions for PM do not take into account any potential excess emissions during startup and shutdown.[120]

DAQ must amend the Draft Permit to ensure that actual emissions from the new auxiliary units will not exceed their respective potential emission values or otherwise contribute to an exceedance of the facility-wide PSD avoidance limits calculated by Duke Energy. DAQ could accomplish this by establishing either: (1) enforceable *facility-wide* PSD avoidance limits; (2) enforceable PSD avoidance limits applicable to the combined emissions from the new emergency engines, auxiliary boiler, dew point heaters, and diesel storage tanks; or (3) enforceable operational limits for these units as needed to limit their emissions to their respective potential emission values. The final permit must also include adequate monitoring, recordkeeping, and reporting requirements to ensure compliance with those limits.[121]

Finally, the Draft Permit does not include *any* PSD avoidance limits for SO_2 or H_2SO_4, whether facility-wide or unit-specific—despite the fact that Duke's own analysis shows that the new gas plant's potential emissions of these pollutants exceed their respective significant emission rate thresholds.[122] As a result, Duke Energy's evasion of PSD review for these pollutants continues to rely on an improper PSD applicability analysis, which is based on an incorrect assumption that there will be zero future emissions Units 1 and 2 when the new gas turbines begin operating. For the reasons detailed above in Section I, this method of calculating future emissions for purposes of PSD applicability is unlawful under North Carolina's State Implementation Plan.

V. The Draft Permit Lacks Adequate Monitoring, Recordkeeping, and Reporting Requirements for Several Emission Units.

While the Draft Permit establishes several monitoring requirements for the new combustion turbines,[123] it does not include sufficient requirements to track compliance with all the applicable limits. Worse, the Draft Permit completely fails to impose effective monitoring

[120] Application Review at 8.
[121] *See* Section V, *infra*.
[122] Application at 3-8 (Table 3-1).
[123] *See* Draft Permit at 84 – 88.

requirements for the other new units. Without adequate monitoring, recordkeeping, and reporting requirements, neither DAQ nor the public will have any way of knowing whether future operations of the new gas plant are in compliance with its permit and the Clean Air Act.

First, DAQ must amend the Draft Permit to include adequate monitoring requirements for the new auxiliary units. At a minimum, this must include monitoring requirements for the pollutants for which PSD avoidance limits have been established as a means for Duke Energy to evade PSD review: total PM, NO_X, VOC, and CO.[124] This is especially needed for NO_X, CO, and VOC, given that Duke itself has admitted that its calculations may have significantly underestimated the potential emissions from these units because the controls for these three pollutants "may not perform optimally under certain operating scenarios."[125] In addition, DAQ should include monitoring requirements to track compliance with other applicable limits, such as (1) the opacity limits applicable to the auxiliary boiler, emergency engines, and dew point heaters;[126] (2) the PM limits applicable to the auxiliary boiler and dew point heaters;[127] and (3) the SO_2 limits applicable to the auxiliary boiler and dew point heaters.[128]

Second, DAQ must amend the Draft Permit to include sufficient monitoring requirements to track compliance with *all* the limits applicable to the new combustion turbines. For example, the Draft Permit does not require any monitoring to ensure compliance with the opacity limit applicable to the turbines.[129] The Draft Permit also fails to include any monitoring, recordkeeping, or reporting requirements for any of the toxic air pollutants that will be emitted.[130]

Commenters note that the Draft Permit does require an initial stack test to be performed "on one of the turbines" to "verify" one of the emission factors that will be used to monitor compliance with the PSD avoidance limit for VOC.[131] We commend DAQ for requiring this confirmational testing. However, DAQ should require this stack test to be performed on *both* turbines instead of just one—and periodically over time, instead of just once. DAQ should also add a condition requiring a permit modification to be submitted if this testing reveals that actual

[124] Draft Permit at 83 (Condition 2.2 C.1.a).
[125] Application at A-1, n.5.
[126] Draft Permit at 52 (Condition 2.1 O.1), 55 (Condition 2.1 P.3), 69–70 (Condition 2.1 R.3).
[127] *Id.* at 55 (Condition 2.1 P.1), 69 (Condition 2.1 R.1).
[128] *Id.* at 55 (Condition 2.1 P.2), 69 (Condition 2.1 R.2).
[129] *Id.* at 60 (Condition 2.1 Q.1.c).
[130] *Id.* at 81 (Condition 2.2 B.1.c).
[131] Draft Permit at 83 (Condition 2.2 C.1.c).

emissions are higher than presumed by the emission factor, similar to what is required in DAQ's draft permit for the Roxboro Steam Electric Plant.[132] In addition, DAQ should impose a similar set of requirements in order to verify (and modify, as needed) *all* of the emission factors that will be used to monitor compliance with the PSD avoidance limits for PM and VOC.[133]

VI. The Final Permit Must Ensure Compliance with Rules Adopted under Clean Air Act Sections 111(b) and (d).

In May 2024, EPA finalized new rules limiting greenhouse gas emissions from fossil fuel-fired electric generating units.[134] Relevant to this permitting action, the final rule established New Source Performance Standards (NSPS) for new fossil fuel-fired combustion turbines with a capacity of at least 250 MMBtu/hour and that commence construction on or after May 23, 2023 ("Subpart TTTTa"), as well as emission guidelines for existing coal-fired steam electric generation units that were constructed before January 8, 2014 ("Subpart UUUUb").[135] The final rule took effect on July 8, 2024.[136]

Under the new emission guidelines, EPA determined that the best system of emissions reduction (BSER) for existing coal-fired steam generating units is to implement carbon capture and storage (CCS) with 90% capture.[137] Under the NSPS, new fossil fuel-fired "intermediate load" combustion turbines must implement "highly efficient simple cycle generation" as BSER.[138]

Duke concedes that the new gas turbines will be subject to Subpart TTTTa.[139] DAQ's Application Review document unequivocally states that the proposed gas turbines "are classified as intermediate-load combustion turbines" within the meaning of Subpart TTTTa, "meaning they supply more than 20 percent but less than or equal to 40 percent of the potential electric output as net electric sales on both a 12-operating month and a 3-year rolling average basis."[140] However, nothing in the Draft Permit restricts the operation of either turbine to this range. In order to ensure compliance with this federal rule, DAQ must establish an enforceable condition for each

[132] Roxboro Draft Permit at 81 (Condition 2.2 E.1.b.iii).
[133] Draft Permit at 86 – 87 (Conditions 2.2 C.1.g.ii –iii).
[134] *See* 89 Fed. Reg. 39,798 (May 9, 2024).
[135] *See id.* at 39,801, 39,806, 39,842, 39,907.
[136] *Id.* at 39,798.
[137] *Id.* at 39,801, 39,802.
[138] *Id.* at 39,802.
[139] Permit Application at 3-10.
[140] Application Review at 19.

new turbine to supply no more than 40% of its potential electric output as net electric sales. In the alternative, DAQ could establish a condition that automatically applies the "more stringent standard of performance" applicable to base load units in the event that either turbine exceeds the specified range.[141]

In addition, neither the Application nor the Draft Permit address compliance with the new emission guidelines for existing coal-fired steam generating units. While Commenters maintain that construction of the new gas turbines is not a "modification" of the existing coal-fired power plant, the Draft Permit treats it as such. If DAQ maintains that the existing coal plant is being modified by this permitting action, then the final permit must include enforceable conditions to ensure those units comply with the BSER and presumptive standard set forth in Subpart UUUUb. If nothing else, the final permit must establish an enforceable deadline for all of the existing coal-fired units to be fully retired by the compliance deadline of January 1, 2032.

VII. The Draft Permit Exacerbates the Deficiencies in North Carolina's Pending State Implementation Plan Submission for the Regional Haze Program.

As explained above, the Draft Permit does not establish a facility-wide emission limit for SO_2 or an enforceable backstop date for the retirement of coal-fired Units 1 and 2. It also does not impose *any* requirements related to the retirement of coal-fired Units 3 and 4. If DAQ were to issue a final permit without establishing an enforceable schedule for Duke Energy to retire the existing coal plant—or at least impose lower emission limits for haze-causing pollutants—that action would severely undermine the representations made by the state to the federal government in North Carolina's State Implementation Plan submission for the Second Implementation Period of the Regional Haze Program, which is currently pending before the U.S. Environmental Protection Agency (EPA).[142]

Emissions from the Marshall facility's existing coal plant have significant visibility impacts on local Class 1 areas. In particular, the Marshall facility is one of the state's top-10 contributors to sulfate impacts at the Shining Rock National Wilderness Area.[143] It is also one of the five facilities in North Carolina that exceeds the state's "area of influence" (AoI) threshold

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[141] 89 Fed. Reg. at 39,909.
[142] *See* 89 Fed. Reg. 67,341, *Air Plan Approval; North Carolina; Second Period Regional Haze Plan (Proposed Rule)* (Aug. 20, 2024).
[143] *Id.* at 67,359; *see also* N.C. DEP'T OF ENV'T QUALITY, DIV. OF AIR QUALITY, FINAL REGIONAL HAZE STATE IMPLEMENTATION PLAN FOR NORTH CAROLINA CLASS I AREAS (2019–2028 PLANNING PERIOD) 219 (Apr. 4, 2022) ("Regional Haze Plan"). (Attachment 3).

due to its emissions' combined sulfate and nitrate impacts at the Linville Gorge and Shining Rick Wilderness Areas.[144] The National Park Service's comments on North Carolina's draft plan noted that the Marshall facility also impacts visibility at the Great Smoky Mountains National Park.[145]

Despite this clear connection between emissions from the existing coal plant and visibility impacts in multiple Class 1 areas, the state failed to perform a "four-factor analysis" for the Marshall facility.[146] The state relied in part on existing and expected measures as a basis to exclude the facility from this required analysis.[147] These measures specifically included Duke Energy's "projected" retirement of "Units 1, 2, 3, and 4 . . . in 2035."[148] However, EPA has clearly explained that in order for a state to rely upon existing or expected measures to make the required demonstration of achieving reasonable progress without performing a four-factor analysis, those measures must be legally enforceable and must be "adopted into the regulatory portion of the [State Implementation Plan]."[149] Unless DAQ establishes an enforceable schedule for retirement of the facility's coal-fired units through this permit, and supplements its plan submission[150] to formally incorporate that retirement schedule, the state's Regional Haze plan will be legally deficient. If EPA ultimately approves North Carolina's plan, that approval may be appealed by interested parties.

Similarly, North Carolina's Regional Haze submission relies on projected 2028 emissions for NO_X and SO_2 as a basis to exclude the Marshall facility from the required four-factor analysis.[151] In particular, the state cites projections that NO_X and SO_2 emissions from the facility will decrease to 5,355.8 tpy and 2,654.2 tpy, respectively, by the end of the Second

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[144] *See* 89 Fed. Reg. at 67,353; Regional Haze Plan at 218–19, 227.
[145] Regional Haze Plan at 339.
[146] *Id.* at 252–54. Notably, the state's exclusion of the Roxboro facility from this analysis contravened a specific recommendation by the National Park Service. *See id.* at 339.
[147] *See id.* at 252–54, 260, 339–40.
[148] *Id.* at 260.
[149] U.S. ENV'T PROTECTION AGENCY, CLARIFICATIONS REGARDING REGIONAL HAZE STATE IMPLEMENTATION PLANS FOR THE SECOND IMPLEMENTATION PERIOD 8-10 (July 8, 2021), https://www.epa.gov/system/files/documents/2021-07/clarifications-regarding-regional-haze-state-implementation-plans-for-the-second-implementation-period.pdf.
[150] In August 2024, EPA proposed to "conditionally approve in part" North Carolina's Regional Haze Plan submission. *See* 89 Fed. Reg. at 67,341. EPA explained that the basis for its proposed approval being "conditional" was "due to concerns with the legal and practicable enforceability of certain permit conditions identified in the Haze Plan for incorporation into the [State Implementation Plan]." *Id.* at 67,342, 67,368. If EPA's proposed conditional approval is finalized, North Carolina will have one year from EPA's final action to submit a plan revision that "adequately addresses" the deficiencies in its original submission. *Id.*
[151] *See* Regional Haze Plan at 254, 256, 258, 339–40.

Implementation Period.[152] However, the Draft Permit proposes to authorize emissions of NO_X and SO_2 far above those levels:

Source	**Emission Unit(s)**	**NO_X (tpy)**
Regional Haze Projections[153]	Facility-Wide	5,355.8
Draft Permit - PSD Avoidance Limit[154]	Units 1, 2, 41, and 42	2,403.8
Projected Emissions - Other Coal Units[155]	Unit 3	2,720.1
	Unit 4	3,624.2
Potential Emissions - Other New Units[156]	Emergency Generator	7.740
	Firewater Pump	0.634
	Dew Point Heaters	8.760
	Auxiliary Boiler	25.7
Total Allowable Emissions		**8,790.9**
Percent Increase over Regional Haze Plan		**64.14%**

Source	**Emission Unit(s)**	**SO_2 (tpy)**
Regional Haze Projections[157]	Facility-Wide	2,654.2
Projected Emissions - Existing Coal Units[158]	Units 1 and 2	1,031.3
	Unit 3	1,686.4
	Unit 4	1,587.7
Potential Emissions - New Units[159]	Simple Cycle Turbines	105.0
	Emergency Generator	0.0078
	Firewater Pump	0.0010
	Dew Point Heaters	0.0530
	Auxiliary Boiler	42.0
Total Allowable Emissions		**4,452.5**
Percent Increase Over Regional Haze Plan		**40.39%**

[152] *Id.* at 253.
[153] *Id.*
[154] Draft Permit at 83.
[155] Draft Permit at 22.
[156] Permit Application at A-7, Table A-6.
[157] Regional Haze Plan at 253.
[158] Draft Permit at 22.
[159] Permit Application at A-7, Table A-6.

Based on these values in the permit application and Draft Permit, it is unreasonable for the state to continue to rely on its previous 2028 emission projections for purposes of avoiding a four-factor analysis for the Marshall facility. Accordingly, DAQ should establish through this permit enforceable facility-wide emission limits of 5,355.8 tpy of NO_X and 2,654.2 tpy of SO_2, effective in 2028, and supplement the state's pending Regional Haze plan to formally incorporate those emission limits.

VIII. The Public Notice Issued for the Draft Permit Was Deficient.

North Carolina's State Implementation Plan[160] requires DAQ to provide public notice of any draft permit for a "source that may be designated by the Director based on significant public interest relevant to air quality."[161] This public notice is required to "identify" specific information related to the draft permit, including "the activity or activities involved in the permit action" and "the emissions change involved in any permit modification."[162] Written comments must then be accepted for "not less than 30 days" after the date of the notice.[163]

Due to significant public interest in the Marhsall facility and its impacts on local and regional air quality, DAQ provided public notice of the Draft Permit on October 17, 2024.[164] However, the public notice did not comply with the requirements of North Carolina's State Implementation Plan. First, the notice failed to provide any information regarding the "emissions change involved" in the permit modification.[165] Second, the public notice's description of the "activities involved in the permit action" was incomplete because it fails to "identify" the new auxiliary boiler, dewpoint heaters, and emergency engines for which construction would be authorized, in addition to the natural gas-fired turbines.

These deficiencies in the public notice may have been relied upon by members of the public to conclude that the Draft Permit was not worth reviewing and/or commenting on. Compounding these deficiencies in the notice, DAQ did not disclose the Continuous Emissions

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[160] North Carolina has a federally approved State Implementation Plan for Clean Air Act permitting. The current plan's approved provisions for construction permits and public participation, which are codified at 15A NCAC 2Q.0300-.0317, were approved by the U.S. Environmental Protection Agency (EPA) in 2021. *See* 86 Fed. Reg. 11,875, 11,875 -11,878, *Air Plan Approval; North Carolina; Revisions to Construction and Operation Permit (Final Rule)* (Mar. 1, 2021).
[161] 15A NCAC 2Q.0306(a)(1).
[162] *Id.* at 2Q.0307(c)(5)–(6).
[163] *Id.* at 2Q.0307(d).
[164] Mark J. Cuilla, *NOTICE FOR PUBLIC HEARING; PRELIMINARY DETERMINATION REGARDING APPROVAL OF AN AIR PERMIT APPLICATION FOR Duke Energy Carolinas, LLC – Marshall Steam Station* (Oct. 16, 2024).
[165] 15A NCAC 2Q.0307(c)(6).

Monitoring System (CEMS) data it possessed for the Marshall facility until November 14, 2024[166]—just six business days before the end of the comment period. This delayed disclosure impeded the ability of Commenters and other members of the public to fully review and evaluate the sufficiency of the Application and Draft Permit within the public comment period.

Accordingly, Commenters respectfully request that DAQ publish an updated public notice that addresses the above deficiencies and accept comments for an additional 30 days, in order to ensure the public has a meaningful opportunity to review and provide input on the Draft Permit.

CONCLUSION

Contrary to Duke's contention, the proposed new gas plant is a brand-new source with emissions that exceed the PSD applicability thresholds for major stationary sources. Thus, construction of the new gas plant cannot reasonably be permitted as a minor modification to the existing coal plant and must go through PSD review. Furthermore, even if it were lawful for DAQ to permit the new gas plant as a modification, Duke has not provided sufficient detail about the data and assumptions underlying its emission calculations to enable DAQ to verify either the netting analysis in the Application or whether the PSD Avoidance Limits will actually ensure compliance with the Clean Air Act. DAQ, in turn, has not included sufficient monitoring requirements in the Draft Permit to ensure that Duke complies with the PSD Avoidance Limits and other applicable requirements. The Draft Permit also undermines North Carolina's pending State Implementation Plan submission for the Regional Haze program. Finally, DAQ's public notice for the Draft Permit was deficient.

For the foregoing reasons, Commenters respectfully request that DAQ either deny the permit or, alternatively, obtain the necessary information from Duke and make significant changes as recommended herein, such as establishing adequate monitoring requirements to ensure compliance with all the applicable limits and the Clean Air Act.

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[166] *See* email from Shawn Taylor, Pub. Info. Officer, N.C. Dept. of Env't Quality, Div. of Air Quality, to Munashe Magarira, Senior Atty, S. Env't L. Ctr, *RE: Documents referenced in air permit application nos. 1800073.24A and 7300029.24A* (Nov. 14, 2024, 9:05 EST) ("The information you've requested is now on Laserfiche," including "Duke Marshall CEMS data") (Attachment 4).

Respectfully submitted,

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