ORAL ARGUMENT SCHEDULED FOR JUNE 2, 2016

No. 15-1363 (and consolidated cases)

IN THE UNITED STATES COURT OF APPEALS
FOR THE DISTRICT OF COLUMBIA CIRCUIT

STATE OF WEST VIRGINIA, *et al.*,

Petitioners,

v.

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY, *et al.*,

Respondents.

On Petitions for Review of Final Agency Action of the
United States Environmental Protection Agency
80 Fed. Reg. 64,662 (Oct. 23, 2015)

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GLOSSARY OF TERMS

Act (or CAA)	Clean Air Act
APA	Administrative Procedure Act
BSER	Best System of Emission Reduction
CO_2	Carbon dioxide
Core Br.	Opening Brief of Petitioners on Core Legal Issues, *West Virginia v. EPA*, No. 15-1363 (and consolidated cases) (D.C. Cir. filed Feb. 19, 2016; final form filed Apr. 22, 2016)
Core Reply	Reply Brief of Petitioners on Core Legal Issues, *West Virginia v. EPA*, No. 15-1363 (and consolidated cases) (D.C. Cir. filed Apr. 15, 2016; final form filed Apr. 22, 2016)
EPA	United States Environmental Protection Agency
EPA Br.	Respondent EPA's Initial Brief, *West Virginia v. EPA*, No. 15-1363 (and consolidated cases) (D.C. Cir. filed Mar. 28, 2016; final form filed Apr. 22, 2016)
ERCOT	Electric Reliability Council of Texas
ESA	Endangered Species Act
GWh	Gigawatt hour
JA	Joint Appendix
lbs CO_2/MWh	Pounds of carbon dioxide per megawatt hour
MWh	Megawatt hour
NACoal	North American Coal
NERC	North American Electric Reliability Corporation

NRECA	National Rural Electric Cooperative Association
Proposal	Proposed Rule, Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, 79 Fed. Reg. 34,830 (June 18, 2014)
PUCT	Public Utility Commission of Texas
Record Br.	Opening Brief of Petitioners on Procedural and Record-Based Issues, *West Virginia v. EPA*, No. 15-1363 (and consolidated cases) (D.C. Cir. filed Mar. 28, 2016; final form filed Apr. 22, 2016)
RIA	Regulatory Impact Analysis
Rule	U.S. Environmental Protection Agency, Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, Final Rule, 80 Fed. Reg. 64,662 (Oct. 23, 2015)
Supplemental Notice	Notice of Data Availability, 79 Fed. Reg. 64,543 (Oct. 30, 2014)
TSD	Technical Support Document
UARG	Utility Air Resource Group

INTRODUCTION AND SUMMARY OF ARGUMENT

The Rule is replete with fatal procedural and record-based flaws that EPA's brief drives home.

First, EPA proposed nothing even vaguely resembling the program in the Rule. EPA contends Petitioners should have divined from a Supplemental Notice of Data Availability ("Supplemental Notice"), 79 Fed. Reg. 64,543 (Oct. 30, 2014), JA131-41, that EPA was contemplating nationwide, uniform rates for coal- and natural gas-fired units (though EPA never mentioned them). It argues Petitioners should have foreseen EPA would abandon its novel proposal. But EPA cannot explain how Petitioners could meaningfully comment on uniform rates when EPA not only never proposed any, but specifically disavowed them in its proposal.

EPA also argues Petitioners' sole recourse is a petition for administrative reconsideration under CAA section 307(d)(7)(B). But that section cannot apply where there has been a wholesale failure of notice. Holding otherwise invites evasion of the rulemaking process.

Second, EPA's conclusions that its best system of emission reduction ("BSER") is "adequately demonstrated" and its national performance rates are "achievable" by every regulated unit remain unsupported. EPA's BSER is not based on a technology demonstrated at any regulated unit anywhere or on operational changes any regulated unit can make to improve its emissions performance. Instead, it rests on speculation about future growth of renewable sources. EPA's BSER (and its presumptions about grid reliability and supporting infrastructure development) assumes the availability of these alternative sources will always increase at their maximum historical rate in each regulated State. EPA's BSER is guesswork, nothing more.

EPA avers that the Rule's "flexibility" allows every source to comply. But no individual regulated source, on its own, can meet the uniform national standards with any demonstrated control technology. *Not one*. There are only two ways an affected unit can meet the national standards: shutter entirely, or (notwithstanding EPA's claim that trading is not part of BSER) obtain tradable emission rate credits produced by EPA-favored sources.

Finally, EPA has no answers to the Rule's many other record flaws. The Rule discriminates against many existing low- or zero-emission generating units, jeopardizes reliability, rests on a deeply-flawed cost analysis, and fails to address State-specific factors making compliance in many States impossible.

These procedural and record deficiencies require vacatur.

ARGUMENT

I. EPA Unlawfully Promulgated a Rule It Never Proposed.

The Rule's "chief regulatory requirement" comprises two uniform, nationally-applicable performance rates: 1,305 and 771 pounds of carbon dioxide per megawatt-hour ("lbs CO_2/MWh") for coal- and gas-fired units, respectively. Final Rule, Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, 80 Fed. Reg. 64,662, 64,820, 64,823 (Oct. 23, 2015) ("Rule"), JA14, JA142-43, JA301, JA304. Every element of the Rule, including each State's goal, derives from these. *See id.* at 64,820, JA301. But this national performance-rate-driven program was never proposed.

EPA proposed an entirely different regulation, driven by State-specific, blended emission rate goals that applied to States rather than individual units.[3] In fact, EPA explicitly rejected any regulation based on uniform, national rates for coal and gas. Proposed Rule, Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, 79 Fed. Reg. 34,830, 34,894 (June 18, 2014) ("proposal"), JA1, JA66. Under the proposal, States were to adopt plans to achieve those State-specific goals by regulating "affected entities" through measures comprising four Building Blocks: affected units (Building Blocks 1 and 2), renewable generation (Building Block 3), and energy consumers (Building Block 4). *Id.* at 34,851, JA23. All affected entities would have been collectively responsible for the emission reductions needed to meet the State's goals. *Id.* at 34,853, JA25.

Subsequently, EPA issued a Supplemental Notice, soliciting comment on calculating the proposal's State-specific goals using *regional* Building Block 2 and 3 targets. *See* Supplemental Notice, 79 Fed. Reg. at 64,543-53, JA131-41. Nothing in it suggested EPA was reconsidering its rejection of uniform national rates or

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[3] A comparison between the proposal and final Rule demonstrates EPA's near-complete rewrite. *See* Attachment.

contemplating a regulation imposing compliance obligations solely on individual affected units rather than on a broad range of "affected entities." The uniform national rate-based program first appeared, unheralded, in the final Rule.

In promulgating a Rule it never proposed, EPA evaded its most fundamental obligation under CAA section 307(d)—to propose its Rule before finalizing it. EPA argues the final Rule's "uniform national rate was simply a more lenient application of the regional approach" because the Rule gives "all states and sources … the benefit of the least-stringent rates calculated in any region," and therefore its "uniform national rate was simply a more lenient application of the regional approach." EPA Br. 110 (emphases omitted). This is a non sequitur: there is no mention of uniform national rates—or even regional rates—in either the original proposal or Supplemental Notice. Instead, the Supplemental Notice explicitly contemplated and reaffirmed EPA's continued use of State-specific goals. EPA solicited comment only on the "appropriate manner in which [Building Block 2] goals could be derived *and allocated among states*" and on appropriate Building Block 3 "*reallocation* criterion." 79 Fed. Reg. at 64,551, JA139 (emphasis added).

EPA next implausibly argues its proposal to set "State-specific goals based on a single, blended rate for both coal- and gas-fired units" was such a "departure" from its own "longstanding practice" in section 111 rulemakings that it was "foreseeable" EPA might "revert to more traditional" uniform rates. EPA Br. 111. Despite expressly *disavowing* such an approach in its proposal, 79 Fed. Reg. at 34,894, JA66, EPA argues Petitioners should have "foreseen" this and commented on rates that were never proposed. EPA cannot establish a regulatory program it never proposed, never noticed for comment, and never described in the barest of terms until the final Rule. *See Int'l Union, United Mine Workers of Am. v. Mine Safety & Health Admin.*, 407 F.3d 1250, 1261 (D.C. Cir. 2005) (vacating rule because agency "did not afford … public notice of its intent to adopt, much less an opportunity to comment on" final approach). Once EPA decided to abandon its proposed approach and establish two nationally-uniform rates that applied only to individual sources rather than state-wide goals that applied to a range of "affected entities," it was required to provide notice and an opportunity to comment, just as it did when it changed direction on its related new source performance standards. *See* 79 Fed. Reg. 1,352 (Jan. 8, 2014), JA4969-71.[4]

The CAA's procedural-error test does not excuse EPA's complete failure to undertake a statutorily-required proceeding. "[W]here the procedural error would have been reversible error under the Administrative Procedure Act ("APA"), § 307(d)(8)

[4] EPA's attempt to justify the sufficiency of its notice regarding the Rule's applicability language also misses the mark. EPA Br. 113-14. While EPA may have proposed language in the new source rule dropping the phrase "constructed for the purpose of" from the applicability language, EPA never proposed abandoning the "sales criterion" requirement that a regulated facility supply a minimum amount of electricity to the grid. 79 Fed. Reg. at 1,459-61, JA5002-04. Rather, EPA consistently *included* the sales criterion in applicability discussions. *See id.*; 79 Fed. Reg. at 34,854, JA26. *Portland Cement Ass'n v. EPA*, 665 F.3d 177 (D.C. Cir. 2011), is inapposite. There, unlike here, the associated rulemaking "expressly invited comment" on the topic at issue, and petitioners commented. *Id.* at 192.

does not restrict [the Court's] power, indeed [its] duty, to reverse EPA's action on procedural grounds. Under that test, EPA's failure to give notice on a major portion of a rule is reversible error." *Small Refiner Lead Phase-Down Task Force v. EPA*, 705 F.2d 506, 543-44 (D.C. Cir. 1983). The CAA's "additional requirement in § 307(d)(9)(D)(i) … that the procedural error is grounds for reversal only if 'arbitrary or capricious'… cannot excuse failure to give adequate notice of a final rule." *Id.* at 544 n.102. EPA's action requires vacatur under traditional APA analysis *and* the CAA.

EPA's reliance on the exhaustion requirements of section 307(d)(7)(B) to bar judicial review is similarly misplaced. In *Mexichem Specialty Resins, Inc. v. EPA*, this Court expressly recognized certain well-established exceptions to those requirements. 787 F.3d 544, 553 (D.C. Cir. 2015) (citing *Randolph-Sheppard Vendors of America v. Weinberger*, 795 F.2d 90, 104 (D.C. Cir. 1986)). Chief among them is that statutory exhaustion requirements do not bar judicial review where "the reasons supporting the [exhaustion] doctrine are found inapplicable." *Randolph-Sheppard*, 795 F.2d at 104-05 (internal quotation marks omitted). Whether EPA acted unlawfully in promulgating a rule that was never proposed is a legal question this Court can resolve without Agency explanation or record. There is nothing to exhaust.

Moreover, "[r]esort to the administrative process is futile if the agency will almost certainly deny any relief" due to its "preconceived position on … the matter." *Id.* at 107 (emphases omitted). Here, any reconsideration proceeding addressing this issue would be a wasteful charade. There is no reason to believe EPA would change its mind on procedural arguments it now so vigorously rejects.

Exhaustion is also excused where the statute's "administrative remedies are inadequate." *Id.* Notice and opportunity to comment have value only before a rule's promulgation. Thus, "petitions for reconsideration [are] not an adequate substitute for an opportunity for notice and comment prior to promulgation of a rule." *Kennecott Corp. v. EPA*, 684 F.2d 1007, 1019 (D.C. Cir. 1982).

Indeed, if section 307(d)(7)(B) barred litigating this procedural issue now, Petitioners would have to file reconsideration petitions objecting to a never-proposed Rule. They would then have to wait many months (or even years) for EPA to act on the petition and initiate the rulemaking EPA should have conducted in the first place. Throughout this ordeal, the regulated parties would be required to comply with an unlawfully promulgated Rule, potentially for many years. The unfairness and absurdity of this underscore that section 307(d)(7)(B) should not be interpreted to bar prompt judicial review of such extreme circumventions of the rulemaking process.

II. EPA Has Not Shown Its BSER is Adequately Demonstrated or Its Emission Guidelines Are Achievable.

Even assuming EPA had legal authority to issue a rule of this type, *see generally* Core Brief and Core Reply, EPA departs so far from the statute and past practice in defining BSER that, in applying this Court's precedent governing whether EPA's "system" is "demonstrated" and its national performance rates are "achievable," EPA focuses, not on application of emission control *to individual sources* as the statute commands, but on the ability of the electric grid to meet demand by shifting from fossil generation to alternative generation. Thus, even EPA recognizes that, to satisfy the statutory "demonstration" and "achievability" tests, EPA's national performance rates must "achieve substantial CO_2 reductions *cost-effectively without adverse energy impacts*" in each State. EPA Br. 13; *see* Record Br. 19-21.

EPA fixates on a mantra—its Rule is "flexible." By this, EPA means States may choose between plans implementing EPA's national performance rates on a unit-by-unit basis, or plans implementing the Rule's state-wide "rate-" or "mass-based" goals, which were calculated from the national performance rates. EPA Br. 15-18; *see also* 80 Fed. Reg. at 64,667, 64,887, JA148, JA368. Because the national rates are the "emission limitation" EPA deems "achievable" using its generation-shifting BSER, their validity will also determine the validity of the statewide goals derived from those rates. EPA's task in promulgating this Rule was therefore to demonstrate the national performance rates are achievable in each regulated State, without impairing reliability. Because this showing is lacking, the Rule must be vacated.[5]

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[5] In reviewing EPA's BSER, EPA is entitled to deference with respect to "scientific data within its technical expertise." *Miss. Comm'n on Envtl. Quality v. EPA*, 790 F.3d 138, 150 (D.C. Cir. 2015). Because EPA's fleet-wide findings regarding "grid reliability" are not "a subject of the Clean Air Act and … not the province of EPA," *Del. Dep't of Nat. Res. & Envtl. Control v. EPA,* 785 F.3d 1, 18 (D.C. Cir. 2015), no deference is owed to EPA's BSER findings.

A. EPA Ignores Its Burden.

EPA's generation-shifting BSER cannot be implemented except with tradable credits. *See* 40 C.F.R. § 60.5880 (defining credits as "tradable compliance instrument[s]"). EPA claims "trading" is not necessary to achieve the Rule's uniform national performance rates, EPA Br. 143, but the Rule belies that. Under 40 C.F.R. § 60.5790(c)(1), a source can achieve these rates only by "generation-shifting," and compliance through generation-shifting can be established *only through* an equation that calculates a "theoretical emission rate" for megawatt-hours generated by an existing fossil unit, where credit is given to that unit for each megawatt-hour generated by another, EPA-preferred generator. *Id.* § 60.5790(c)(2). Consequently, any shortfall in credits in a State necessarily reduces the amount of fossil generation that can lawfully be produced there. Record Br. 9-11, 36. Without these credits, the fossil units must shut down, and shortfalls in electric supply are likely. *Id.* at 36.

To justify the national performance rates, EPA's fleet-wide demonstration projects unimpeded generation-shifting, *nationwide*. Generation-shifting on this scale cannot occur without a robust credit trading program in which all States participate. The Rule, however, does not establish any interstate trading program, much less a national one.

While voluntary participation in regional or national trading programs by a State is possible, it is an "option" that may not materialize.[6] As a result, EPA was required to show its national performance rates are achievable, and its BSER demonstrated, assuming only the credit transfer authority each State possesses: intrastate management authority over the credits that can be produced within that State.[7] Therefore, only a state-by-state evaluation could support the findings required to sustain the national rates.

As Petitioners have shown, Record Br. 53-55, EPA's national fleet-wide assessment did not evaluate whether generation-shifting could ensure cost-effective

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[6] It is also uncertain whether a sufficiently robust interstate trading program—a non-BSER measure EPA cannot rely upon to establish achievability—will emerge to enable source owners to achieve compliance. Record Br. 51-52. Experience with other trading markets developed under very different circumstances does not establish that adequate trading markets will develop here, particularly given the Rule's affirmative restrictions inhibiting trading. *Id.* EPA's arguments that Petitioners have not shown such restrictions will prevent the development of sufficiently robust trading markets, EPA Br. 146, misses the point. It is *EPA's* statutory burden to show its Rule is feasible, not Petitioners' burden to show otherwise.

[7] EPA claims a source owner may comply with the national performance rates through investments in increased generation from the owner's existing gas or new renewable facilities, investments in new renewables, or agreements to purchase power from such facilities. EPA Br. 143. Not really. Those "investments" have to create credits that the "investor" can use to calculate compliance with the performance rates. 40 C.F.R. § 60.5790(c)(1). Because credits generated by facilities within a State are "instruments" issued by that State, under conditions which may be imposed by that State, the degree to which EPA's "investment" option creates a flow of credits generated in one State that can be used in another is unknown, and has not been evaluated by EPA. At most, it would represent a very small fraction of the massive interstate trading market implicit in EPA's fleet-wide assessment.

emission reduction and a reliable electricity supply in every State. EPA argues only that the nation's *fleet* as a whole can be rearranged—not that individual sources in that fleet can comply. *See* generally EPA Br. 117-42. In fact, EPA disclaims any obligation to demonstrate that "every individual source can comply with the uniform rates." *Id.* at 141. Consequently, as discussed below, EPA's fleet-wide assessment cannot satisfy EPA's section 111(d) burden of showing its national performance rates are achievable through application of the BSER in each State. *See Nat'l Lime Ass'n v. EPA*, 627 F.2d 416, 431 n.46 (D.C. Cir. 1980).

B. EPA's Fleet-Wide Assessment Is Inadequate To Show State-by-State Achievability Of the Rates.

By offering only high-level descriptions of what the entire industry might accomplish on a regional or national basis, EPA has not shown *any* individual source can comply solely through application of BSER—much less that sources in different States nationwide, affected by different variables and adverse circumstances, can do so, as required by *National Lime*, *id.* at 431 n.46, 433. In fact, even if EPA had undertaken such an evaluation, it would not support EPA's conclusion that the performance rates are achievable through EPA's BSER. For instance, in States like Kentucky, Montana, North Dakota, Virginia and Wyoming, there is little or no existing natural gas generation to achieve Building Block 2. In others, including Kentucky, renewable energy potential is wholly inadequate to implement Building Block 3. *See EPA,* GHG Abatement Measures Technical Support Document ("TSD") at 4-40-4-41, EPA-HQ-OAR-2013-0602-0437 ("GHG Abatement TSD"), JA2850-52; Basin Electric Power Cooperative ("Basin") Comments 25-27, EPA-HQ-OAR-2013-0602-23574, JA1958-59.[8]

Moreover, commenters recounted many difficulties with EPA's plan—highlighting unique generation and transmission constraints rendering compliance by various sources and States exceedingly difficult, extraordinarily expensive, or even impossible. *See generally* EPA Response to Comments Ch. 3 § 3.2 32-59, EPA-HQ-OAR-2013-0602-36876, JA3383-410. EPA never addresses how these problems can be solved; instead, it once again recites its "flexibility" mantra and passes the buck to the States: "We are providing states with substantial flexibility as to how they structure [their] plans to achieve the 111(d) requirements," and "[t]he Building Blocks are not prescriptive, and states may consider local circumstances as they develop their plans, including system reliability, fuel diversity, other regulatory requirements, infrastructure, and the 'useful life' of generation assets." *E.g., id.* at 34, 37, JA3385, JA3388.

Vague promises of "flexibility" do not show that these problems have even been evaluated by EPA, much less that they are surmountable. Rather, EPA must

[8] EPA *proposed* its now-abandoned 1,844 lbs/MWh emission goal for Kentucky coal-fired sources based on these limitations. 79 Fed. Reg. at 34,957, JA129.

show sources can comply, using its BSER, across the wide range of situations sources may encounter in each State. *Nat'l Lime*, 627 F.2d at 431 n.46. EPA cannot do so.

Kentucky's quandary again illustrates the chasm between EPA's modeled projections and on-the-ground-reality. Kentucky's generation fleet contains nearly all coal-fired units, plus a single gas unit. LG&E and KU Energy LLC Comments 4, EPA-HQ-OAR-2013-0602-31932, JA2274. Because the Rule already imputed an unachievably high capacity factor to the single gas unit, Building Block 2 is effectively unavailable in Kentucky. Kentucky's mere 4% in-state renewable energy potential also severely limits Building Block 3. *Id.*; GHG Abatement TSD at 4-40, JA2851. Yet EPA makes no showing that Kentucky sources can apply EPA's BSER to achieve the national performance rates, or that Kentucky can craft a workable state plan. All EPA says is that Kentucky has a lot of "flexibility." EPA cannot avoid its statutory burden by hiding behind such loose words.

C. EPA Has Not Shown Its Building Blocks Are Adequately Demonstrated or Achievable.

The building blocks that form the basis of EPA's fleet-wide assessment are themselves based on speculation and assumption. Rather than rubber-stamp these assertions with "extreme deference," this Court must give each a "hard look." *Small Refiner*, 705 F.2d at 520.

1. Building Block 1 is neither adequately demonstrated nor achievable.

EPA misconstrues Petitioners' argument as asserting that EPA "erred in making projections based on statistical modeling instead of the application of specific measures." EPA Br. 119. EPA's Building Block 1 methodology is *not* based on statistical modeling. EPA calculated the targets by simply adjusting historical heat rate data to conform to EPA's unfounded assumptions about future unit performance.

Even if EPA's assumptions constituted a "model," "model assumptions must have a rational relationship to the real world." *West Virginia v. EPA*, 362 F.3d 861, 866-67 (D.C. Cir. 2004). EPA admittedly did not base its targets on any specific measures available to units, EPA Br. 119-20, and thus did not articulate any "rational relationship" between its estimated improvements and actual measures it believes could achieve them. In particular, EPA did not assess what measures units are already implementing, notwithstanding that the "best operating practices" EPA identifies as capable of improving heat rates are already "standard operating procedure" in the industry and cannot support further improvements. 80 Fed. Reg. at 64,792, JA273.[9]

EPA also failed to account for uncontrollable factors affecting units' heat rates, particularly changes in capacity factor and temperature. These are not simply variables

[9] EPA concedes benefits from these measures degrade over time. EPA Br. 121. EPA's response—that units must periodically remediate that degradation—means units must *overshoot* the target and undertake additional heat rate improvements when their performance approaches the target.

that "might conceivably have pulled the analysis's sting." EPA Br. 121. They are primary drivers of heat rate. EPA, Greenhouse Gas Mitigation Measures Technical Support Document at 3-5, EPA-HQ-OAR-2013-0602-36859 ("GHG Mitigation TSD"), JA3151 (capacity factor accounts for up to 50% of variation). At most, EPA partially accounted for these factors' effects on *past* heat rates. It did not control for the Rule's forced *future* changes in capacity factor, which will skew units toward more inefficient operation. The Rule, by its own terms, will significantly affect important operating conditions that in turn affect units' heat rates. Record Br. 24-25. EPA takes no account of this.

2. Building Block 2 is neither adequately demonstrated nor achievable.

Building Block 2 assumes the entire gas fleet can generate at a 75% capacity factor, representing a 66% increase in utilization over 2012 levels. Record Br. 27-28. EPA's response, EPA Br. 123-29, ignores the most salient fact: the existing fleet has never come close to achieving a 75% capacity factor. *See* GHG Mitigation TSD at 3-5, JA3151 (historic annual capacity factors are 40-50%). Nor has EPA shown the entire fleet can achieve this utilization over a sustained period *while providing reliable generation*. EPA concedes projections about improved future performance require "'substantial evidence that such improvements are feasible.'" EPA Br. 124 (citations omitted). Supporting evidence is conspicuously lacking here.

EPA notes that 88% of gas units operated at the target level for at least *a single day* in 2012.[10] EPA Br. 125. But EPA provides no explanation for how one day of high utilization demonstrates the entire fleet can replicate that high target day-after-day, year-after-year, when many units are incapable of operating at significantly higher capacities on a long-term basis. *See, e.g.*, Basin Comments 49-51, JA1963-65; Utility Air Resources Group ("UARG") Comments 230-31 & Att. C 19-23, 36, EPA-HQ-OAR-2013-0602-22768, JA881-82, JA897, JA915-19, JA932; Record Br. 28.

EPA also dismisses Petitioners' arguments that permit limits often constrain generation, claiming "the record shows very few air permits" with operational limits. EPA Br. 126. For this, EPA relies on *one* comment examining a narrow set of permits, ignoring numerous record examples of permits *with* operational limits. *Compare* Clean Air Task Force Comments 70-75, EPA-HQ-OAR-2013-0602-22612, JA678-83 (reviewing permits in parts of six States), *with* UARG Comments 230 & Att.C 23-24, JA881, JA919-20 (citing specific permit constraints); National Rural Electric Cooperative Association ("NRECA") Comments 92, EPA-HQ-OAR-2013-0602-33118, JA2315; Basin Comments 51, JA1965.

EPA similarly dismisses transmission constraints where existing gas units with excess capacity operate far from the demand. In claiming "the fundamental nature of

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[10] Petitioners did not claim EPA should have disregarded 2012 data. EPA Br. 124. They merely noted that, even in a year with historically low gas prices, only 15% of the fleet reached EPA's target utilization. Record Br. 28.

the interconnection" can resolve these concerns, EPA Br. 129, EPA reveals its ignorance. Generators face transmission constraints and other practical barriers that *prevent* generators in one area from meeting demand in another, even across the same interconnection. *See* UARG Comments 239-40, JA890-91; Basin Comments 51-52, JA1965-66.

As to under-construction units, EPA cites no evidence that generation beyond the Lee Plant's assumed capacity factor of 55% specifically, or any under-construction unit generally, replaced generation from "retired, higher-emitting coal units." EPA Br. 131-32. The record *contradicts* EPA's "replacement effect" argument: although EPA now claims the 55% capacity factor for under-construction sources was intended to capture only their incremental addition to total power generation, at proposal EPA plainly stated the 55% capacity factor was chosen because it "was the average capacity factor for these units," *including* any hypothetical "replacement effect." EPA, Proposed Goal Computation TSD at 12, EPA-HQ-OAR-2013-0602-0460, JA2864. EPA's new argument is an impermissible post-hoc litigation position. *See Nat. Res. Def. Council v. EPA*, 755 F.3d 1010, 1020-21 (D.C. Cir. 2014).

EPA's defense regarding its inclusion of duct burner capacity in Building Block 2 also lacks merit. Duct burner capacity boosts power output *temporarily* and cannot be used continually at most units without causing accelerated wear. Record Br. 32-33. EPA avers this is wrong because *some* of the units that operated at 75% capacity in 2012 have duct burners. EPA Br. 132. But these units may have used their duct burners to gain premium energy prices during high demand periods, fully understanding the resulting accelerated equipment wear. EPA's "evidence" does not show what EPA purports—that it is economically feasible for all units to continually operate duct burners.

EPA also fails to account for the inevitable deterioration of existing units. Because Building Block 2 applies only to units existing in 2012, which will eventually deteriorate and retire, the pool of gas units available for generation-shifting will never replenish. Even if 80% of the fleet is "relatively young," EPA Br. 128 n.103, EPA fails to account for the other 20%. Nor does EPA consider that by 2030 about 20% of the existing fleet will be beyond EPA's assumed 30-year useful life, and another 72% will be 21-30 years old. *See* GHG Mitigation TSD at 3-7, Table 3-1, JA3153. Within another ten years, almost all of the fleet will be beyond EPA's assumed useful life, and generation-shifting under Building Block 2 will be impossible.

3. Building Block 3 is neither adequately demonstrated nor achievable.

EPA claims its assumptions about projected growth in renewable energy are "conservative." EPA Br. 134-36. Not so. Non-hydroelectric renewable energy generation in 2012 totaled about 188,400,000 MWh. U.S. Energy Information Administration Annual Energy Outlook 2015 at A-31, EPA-HQ-OAR-2013-0602-36563, JA2930. EPA projects new non-hydroelectric renewable generation in 2030 will be 706,030,112 MWh, EPA Br. 134, *nearly five times greater* than it was in 2012, with such energy *nearly tripling* between 2022 and 2030. GHG Mitigation TSD at 4-9, Table 4-9, JA3177. EPA's projections assume that from 2024-2030 each individual renewable technology will "grow at [its] *maximum* [annual] historical pace." EPA Br. 134. In other words, EPA has identified a different single high year of growth for each technology and concluded that future growth for each technology will occur simultaneously, at this maximum rate, for seven consecutive years. EPA assumes this even though the different renewable resources compete with each other for investments and demand for capacity, transmission infrastructure, and energy. EPA has no explanation or technical basis for this assumption. Indeed, the *average* growth rate for each of the renewable technologies was less than half its *maximum* growth rate, GHG Mitigation TSD at 4-2, Table 4-1, JA3170, thoroughly undermining EPA's assumption.

The studies EPA cites also fail to support its assumption. EPA Br. 136. These studies reflect that incorporating significant amounts of new renewable energy raises extraordinarily complex technical issues requiring further in-depth study. As the National Renewable Energy Laboratories notes:

> The scenarios developed … do not in any way constitute a plan; instead, they should be seen as an initial perspective on a top-down, high-level view of four different 2024 futures. The transition over time from the current state of the bulk power system to any one of the scenarios *would require additional technical and economic evaluation, including detailed modeling of power flows and a study of the effects on the underlying transmission systems*. A more thorough evaluation of the sensitivity of the … results to the range of assumptions

> made would also be required to guide the development of any specific bottom-up plans.

National Renewable Energy Laboratories, Eastern Wind Integration and Transmission Study at 28, *available at* www.nrel.gov/docs/fy11osti/47078.pdf, JA4670 (cited by EPA in GHG Mitigation TSD at 4-20 n.36, JA3188) (emphasis added).

EPA conducted no assessment to determine what can actually be achieved. EPA punts and says it expects States, sources, and others to conduct these assessments during the state planning process. *See* EPA Br. 151. That those future analyses may show that renewables will not be available, however, underscores that EPA should have shown *in this rulemaking* that its Building Block 3 targets are adequately demonstrated and achievable.

4. EPA's modeling cannot support the achievability of Building Blocks 2 and 3.

EPA's reliance on its Integrated Planning Model is misplaced. EPA modeled Building Blocks 2 and 3 in isolation. It never modeled them together to show they can be achieved in tandem under a Rule requiring that every megawatt-hour of existing gas generation be offset by a renewable credit and every megawatt-hour of coal-fired generation be offset by both gas and renewable credits. *See* EPA, IPM Run Files for Supporting Scenarios for GHG Mitigation Measures TSD, https://www.epa.gov/airmarkets/ipm-run-files-supporting-scenarios, JA5448 (showing separate Building Block 2 and 3 model runs); EPA CO_2 Emission Performance Rate and Goal Computation TSD at 13-15, EPA-HQ-OAR-2013-0602-36850, JA3039-41.

Consequently, EPA has not shown sufficient generation can be shifted to support Building Blocks 2 and 3 given transmission, dispatch, and reliability constraints.[11] Accordingly, EPA's modeling does not demonstrate the achievability of Building Blocks 2 and 3. *See Appalachian Power Co. v. EPA*, 249 F.3d 1032, 1053-54 (D.C. Cir. 2001) ("[M]odel assumptions must have a 'rational relationship' to the real world," and EPA must explain why its assumptions and methodology are reasonable).

D. EPA Failed To Meaningfully Assess Infrastructure and Reliability Concerns.

1. The record does not support EPA's findings on lack of infrastructure needs.

EPA has not shown the infrastructure needed to support Building Blocks 2 and 3 exists or can be developed in time to achieve EPA's limits. EPA relies primarily on its own conclusory statements, EPA Br. 148-50, while largely ignoring warnings from

[11] The modeling for EPA's Regulatory Impact Analysis ("RIA"), which did address both Building Blocks, did not cure this. The modeling outputs for existing gas unit capacity factors and renewable generation were far less than EPA's BSER assumed were achievable—for gas, 54% in the mass-based scenario, and 61% in the rate-based scenario, far short of the assumed 75%. Regulatory Impact Analysis Revised Technical Corrections 3-25, EPA-HQ-OAR-2013-0602-37105, JA3657. So too for non-hydroelectric renewable generation, which were far short of the BSER's assumed 864,000 gigawatt-hours. *Compare* EPA, Analysis of the Clean Power Plan, BB3-Cost-Effectiveness SSR at Summary Tab (*available at* www.epa.gov/airmarkets/ipm-run-files-supporting-scenarios) (BB3: Cost-Effectiveness (Zip)), JA6287-89, *with EPA,* Analysis of the Clean Power Plan, Rate-Based SSR at Summary Tab (*available at* www.epa.gov/airmarkets/analysis-clean-power-plan) (Rate-Based analyses of the Rule)), JA6293-96 *and* EPA, Analysis of the Clean Power Plan, Mass-Based SSR at Summary Tab (*available at* www.epa.gov/airmarkets/analysis-clean-power-plan) (Mass-Based analyses of the Rule), JA6290-92.

grid regulators, Record Br. 38-39.

EPA cites a Department of Energy report to argue the "limited amount" of transmission construction the Rule requires is within historical ranges. EPA Br. 149. EPA posits that the average 870 miles/year of total new transmission *for all purposes* added from 1991-2011 is similar to the 890 miles/year supposedly needed to accommodate *new wind capacity only* under Building Block 3, based on an assumed addition of 115 gigawatts of wind capacity each year from 2021-2030. *Id.* But EPA ignores *any* transmission necessary to accommodate solar and other non-wind renewables included in Building Block 3. EPA's own model assumes total new renewable capacity additions from 2020-2030 will be 202 gigawatts—far more than the 115 gigawatts projected for wind alone. EPA, Analysis of the Clean Power Plan, BB3-Cost-Effectiveness SSR at Summary Tab (*available at* www.epa.gov/ airmarkets/ipm-run-files-supporting-scenarios) (BB3: Cost-Effectiveness (Zip)), JA6287-89.

Moreover, nothing supports EPA's prediction that sufficient transmission can be in place to support the interim standards beginning in 2022. Critically, EPA did not respond to concerns expressed by the North American Electric Reliability Corporation ("NERC") and regional transmission organizations that EPA has not allowed sufficient time to build the necessary transmission (and generation) without affecting grid reliability. *See* Record Br. 39-40. NERC indicates that because new transmission takes up to fifteen years to engineer, site, permit, and construct, adequate infrastructure likely will not be in service to meet the Rule's interim deadlines. NERC, Potential Reliability Impacts of EPA's Proposed Clean Power Plan viii, 32, EPA-HQ-OAR-2013-0602-37007, JA3458, JA3491.

Extending that interim compliance date two years, EPA Br. 152, does not eliminate NERC's concern. A new transmission project is a massive undertaking, involving acquisition of miles of rights-of-way, resolution of environmentally-sensitive impacts, complex permitting, financing, design, and construction activities, and possible litigation that can take ten to fifteen years to resolve. *See, e.g.*, UARG Comments 233-36, JA884-87; NRECA Comments 105-07, JA2316-18; Basin Comments 25-28, JA1958-61. EPA ignores these realities.

2. EPA has not shown its Rule will preserve grid reliability.

EPA has not shown its Rule will ensure grid reliability, although EPA acknowledges that reliable transmission of electricity is required. EPA Br. 13, 122, 139. EPA claims "published reports and analyses" show the Rule's national performance rates will not threaten reliability. *Id.* at 150-51. But the only reports EPA cites do not support that assertion. They offer no specific plan or strategy to ensure reliability but assume States and industry will figure it out while applying the Rule's so-called "flexibility." *Id.* Again, EPA fails to respond to concerns expressed by authoritative sources like NERC that the Rule's transformative changes present significant reliability concerns that could profoundly affect the nation's security and its citizens' well-being. Record Br. 42-43.

Reliability Safety Valve. EPA's "reliability safety valve," EPA Br. 152, offers no meaningful protection. It provides a one-time 90-day relief period, in emergencies, for individual units. 80 Fed. Reg. at 64,878, JA359. EPA claims it can extend this period if "there is still a serious, ongoing reliability issue," EPA Br. 152 (citation omitted), but under the Rule any excess emissions beyond those authorized in the state plan count against the State's overall performance rate. 80 Fed. Reg. at 64,879, JA360. The "safety valve" is illusory.

Challenges in the Electric Reliability Council of Texas ("ERCOT"). EPA's faulty reliability analysis presents particular problems within ERCOT. While EPA claims to have "determined achievable emission limitations based on measures that could reliably be implemented *within* this region," EPA Br. 153-54, it fails to take into account that ERCOT is fundamentally based on a free-market electricity generation system. EPA's conclusion that system reliability will be unimpaired was based on *assumptions* about reliability built into EPA's modeling. EPA, Resource Adequacy and Reliability Analysis TSD at 3, EPA-HQ-OAR-2013-0602-36847, JA2948; *see* Public Utility Commission of Texas ("PUCT") Comments 30, EPA-HQ-OAR-2013-0602-23305, JA1631. But the model is not appropriate for assessing reliability because it assumes lost generating capacity below an area's reserve margin will simply be added to fill the loss—an unreasonable assumption in ERCOT, where the State cannot force the construction of new capacity. *See* Tex. Util. Code Ann.

§ 39.001; PUCT Comments 1, 4, JA1602, JA1605 (within ERCOT only transmission and distribution are subject to traditional regulation).

EPA also incorrectly dismisses ERCOT's inability to import power from outside the region. EPA Br. 129. In addition to the significant strains on reliability caused by coal-fired plan retirements in this small "power island," this feature of ERCOT has other implications, including possible asymmetries between future emissions trading markets under the Rule and electricity markets. If emissions credits can be traded across state lines where electricity cannot flow, it could have reliability implications for the ERCOT region, where associated integration issues (*i.e.*, system costs and reliability impacts due to increased variable generation and the need for additional transmission) would need to be addressed. *See* PUCT Comments 74, JA1675.

Challenges for Cooperatives. EPA further fails to address the cost and reliability concerns facing many rural electric cooperatives. The communities dependent on cooperatives are among the most vulnerable in America. NRECA Comments 2-3, 129-30, JA2309-10, JA2319-20. EPA brushes off disproportionate impacts on these communities, casually asserting the Rule provides "different ranges of opportunities" for compliance. EPA Br. 155. What opportunities? Cooperatives are severely constrained—by geography, resource availability, financial wherewithal, and the mandates of the Rural Electrification Act. Record Br. 46-47.

EPA again retreats behind "flexibility," claiming States can "implement a broad range of approaches." EPA Br. 155. Chief among these are credit trading programs EPA claims will allow cooperatives to purchase credits or allowances and recoup the cost through rate increases. *Id.* at 104, n.87. But many cooperative member-customers cannot bear the rate increases that will result from redispatch away from low-cost coal units. Generation & Transmission Cooperative Fossil Group Comments 22, EPA-HQ-OAR-2013-0602-23164, JA1356; NRECA Comments 2-3, 129-30, JA2309-10, JA2319-2320; Western Farmers Comments 14, EPA-HQ-OAR-2013-0602-23644, JA2017-18. The Rule thus uniquely harms cooperatives by effectively overriding the States' statutory discretion to consider "other factors," like cooperatives' statutory mandate to provide reliable and affordable electricity to rural America, in setting section 111(d) standards.

Modeling Limitations. Finally, EPA argues its modeling addresses reliability concerns. EPA Br. 153. In fact, the model's limitations preclude its use to predict the achievability of generation-shifting while maintaining reliable. For instance, the model: (1) dispatches only on a seasonal basis, (2) does not assess intraregional transmission and distribution infrastructure, and (3) does not model actual facilities, but aggregates facilities to create model plants. Kansas Corp. Comm'n Comments 19-21, EPA-HQ-OAR-2013-0602, JA479-81; EPA Documentation for EPA Base Case v.5.13, Using the Integrated Planning Model at 2-5-2-6, EPA-HQ-OAR-2013-0602-0212, JA2355-56 (model aggregates 16,330 existing plants into 4,971 model plants). A more complex dispatch model is needed to assess whether changes to the electric grid can be undertaken while maintaining reliable power for all customers at all times. Kansas Corp. Comm'n Comments 19-21, JA479-81. EPA chose not to use those more accepted modeling tools and, therefore, failed to assess a critical element of its generation-shifting scheme.

Indeed, EPA concedes it addressed reliability only "at a general level," suggesting local reliability concerns could be assessed at the planning and implementation stage when more information is available. EPA Br. 153. But if EPA intends to undertake an ambitious program of nationwide generation-shifting, it should at the very least be required to show the resulting mix of generating resources will provide reliable power nationwide.

III. EPA Failed To Consider Important Aspects of Its Rulemaking.

A. EPA Penalizes Many Low-Emission Generation Resources.

EPA's supposed distinction between pre- and post-2013 renewable generating facilities is arbitrary and capricious, and its treatment of States with significant pre-2013 renewable development showcases its failure to demonstrate achievability across a wide range of circumstances.

EPA's stated rationale for this distinction—that it has already been accounted for in the Rule's emissions baseline, EPA Br. 165—is incorrect. Nothing in the Rule indicates that any early-adopting States' 2012 emission baseline was adjusted to account for low- or zero-emission generation.

EPA claims Petitioners failed to demonstrate that pre-2013 renewable energy will cease operating as a result of the Rule's prohibition on providing credits to these units. *Id.* at 167. But it is *EPA's* burden to show a rational distinction between identical sets of resources, and to demonstrate that the numerous States and sources already heavily invested in renewable energy technology can implement the significant additional generation-shifting required by its BSER.[12] Because EPA has failed to do so, its actions are arbitrary and capricious.

Without explanation, EPA also arbitrarily discounted the value of waste-to-energy electricity to account for anthropogenic carbon emissions. Record Br. 60-62. EPA's claim that its rationale should have been "self-evident," EPA Br. 168, is belied by juxtaposing: the Rule's call for a broad, flexible approach to reduce greenhouse gas emissions, 80 Fed. Reg. at 64,665, JA146; EPA's recognition that one of the best ways to achieve that objective is to reduce methane emissions, 80 Fed. Reg. 52,100, 52,105 (Aug. 27, 2015); and waste-to-energy's undisputed role as a major net reducer of greenhouse gases from landfill methane, *the nation's largest source of methane*.[13] EPA's disregard of those substantial benefits is fatal.

[12] EPA asserts the development of pre-2013 renewable energy will ease States' compliance burdens, EPA Br. 165, but can offer no record support for this conclusion because EPA never analyzed the ability of individual States and sources to implement its BSER.

[13] EPA, Draft Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2014, at 7-1 (Feb. 22, 2016), https://www3.epa.gov/climatechange/Downloads/ (Continued...)

B. The Rule Unlawfully Prohibits the Use Of Affected Units' Carbon Dioxide in Enhanced Oil Recovery.

The Rule imposes unworkable obstacles to enhanced oil recovery by limiting the injection of captured CO_2 to Subpart-RR compliant facilities. EPA sidesteps these issues, EPA Br. 163, and its failure to address them was arbitrary and capricious. EPA concedes it never proposed subjecting existing sources to Subpart RR. Because of this, no commenter addressed the adverse impact of Subpart RR on the $6-billion Kemper facility, built with the Department of Energy's active support, and on its associated CO_2 offtake contracts.

C. EPA Failed to Establish Necessary Subcategories.

EPA failed to establish subcategories for different types of coal units, in violation of 40 C.F.R. § 60.22(b)(5) (EPA "will specify different emission guidelines or compliance times or both for different sizes, types, and classes of designated facilities when … appropriate"). Here, establishing subcategories was not only appropriate, but necessary, as Petitioners demonstrated that coal units have varying characteristics warranting subcategorization. *See, e.g.*, North American Coal Corp. ("NACoal") Comments 20-22, EPA-HQ-OAR-2013-0602-22519, JA550-52; Luminant Generation Company ("Luminant") Comments 83-84, EPA-HQ-OAR-2013-0602-33559, JA2348-49.

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ghgemissions/US-GHG-Inventory-2016-Main-Text.pdf, JA6228-29; *see also* EPA, Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2013 at ES-14, 2-21, EPA-HQ-OAR-2013-0602-36479, JA2922-24 (third largest in 2013).

EPA argues subcategorization is entirely discretionary, EPA Br. 159, notwithstanding the regulation's use of the mandatory "will." But the case EPA cites addresses a differently-worded statute and is inapposite. *Id.* at 159-60 (citing *Consumer Fed'n of Am. v. HHS*, 83 F.3d 1497, 1504 (D.C. Cir. 1996)). Under EPA's section 111 regulations, it is arbitrary and capricious for EPA not to subcategorize where circumstances demonstrate subcategorization is appropriate. EPA's reliance on *White Stallion Energy Ctr., LLC v. EPA*, 748 F.3d 1222, 1249 (D.C. Cir. 2014), is unavailing because the statutory provision at issue there stated that EPA *may* establish subcategories, while the regulation here states that EPA *will* establish such subcategories where appropriate. *Compare* 42 U.S.C. § 7412(d)(1), *with* 40 C.F.R. § 60.22(b)(5).

EPA wrongly asserts the record does not allow EPA to "discern" a basis for subcategorization. 80 Fed. Reg. at 64,760, JA241. Unrefuted record evidence demonstrates that various classes of coal units differ in significant ways that will impair compliance with the Rule. *See* EPA Response to Comments Ch. 2 § 2.6 at 66-76, EPA-HQ-OAR-2013-0602-36876, JA3368-78. For example, commenters identified affected units that could not reasonably achieve the Rule's proposed performance rate by implementing the BSER. *See, e.g.*, NACoal Comments 20-22, JA550-52; Luminant Comments 83-84, JA2348-49. Moreover, EPA relied on these very same factors in establishing electric generating unit subcategories under another rule. Record Br. 67. EPA's failure to at least explain these different outcomes is arbitrary and capricious.

D. EPA's Cost Consideration Is Fundamentally Flawed.

EPA concedes section 111(a) requires consideration of costs but fails to respond to Petitioners' argument that the Rule's domestic costs dwarf its domestic benefits. EPA contends it need not weigh costs against benefits. EPA Br. 156-57. But the Supreme Court made clear in *Michigan v. EPA* that "[i]t is not … rational … to impose billions of dollars in economic costs in return for a few dollars in … benefits." 135 S. Ct. 2699, 2707 (2015).

EPA again relies on inapposite precedent. EPA Br. 156 (citing *Portland Cement Ass'n v. Train*, 513 F.2d 506, 508 (D.C. Cir. 1975)). In *Portland Cement*, the Court instructed EPA to account for cost-benefit analyses "adduced in comments," and EPA conceded it could not adopt rules with a "gross disproportion" between costs and benefits. 513 F.2d at 508. In any event, *Michigan*'s prohibition on rules with "costs far in excess of benefits" resolves any doubt. 135 S. Ct. at 2711. EPA's *ipse dixit* reliance on benchmarks like the costs of regulating *other* pollutants or the costs of *other* carbon-reduction strategies is unlawful, as well as unreasonable.

EPA unlawfully compared "apples to oranges," *Nat'l Ass'n of Home Builders v. EPA*, 682 F.3d 1032, 1040 (D.C. Cir. 2012), assessing *domestic* costs against *global* benefits measured by the *global* "social cost of carbon." But EPA never disputes the CAA's purpose—to "protect and enhance the quality of *the Nation's* air resources [for]

… *its* population," CAA § 101(b) (emphases added)—which prohibits reliance on global benefits. EPA also failed to respond to record documents demonstrating the fatal flaws with the global Social Cost of Carbon, which the National Academy of Sciences recently also identified. Record Br. 70.

EPA measured only compliance costs, 80 Fed. Reg. at 64,750, JA231, but costs must include "more than the expense of complying with regulations," *Michigan*, 135 S. Ct. at 2707. EPA points to no consideration of costs associated with energy prices, energy reliability, and employment, or the corresponding effects on human health and mortality—all discussed in comments. Record Br. 71.

EPA fails to respond to arguments presented on pages 70 and 71 of the Record Brief. EPA effectively admits it did not account for the Clean Energy Incentive Program and carbon leakage. EPA argues the program merely "compensat[es]" for carbon "reductions prior to the start of the Rule's performance period," EPA Br. 158, but it actually generates credits for up to 300,000,000 tons of emissions the Rule *would otherwise prevent*. This benefit reduction is admittedly "not reflected" in the RIA. RIA at 3-45, JA2497. Finally, EPA did not account for industry relocating to less-regulated countries in response to energy price increases, EPA Br. 159 (citing RIA at 4-5, 5-4 (Table 5-1), JA2541, JA2636), but merely called it "noteworthy," RIA at 5-5, JA2637. EPA is prohibited from refusing to consider such "disadvantages." *Michigan*, 135 S. Ct. at 2707.

IV. EPA Cannot Explain Its Failure To Address Individual State Circumstances.

The arbitrariness of EPA's action is further demonstrated by the harm that will befall many States due to EPA's failure to address specific State circumstances. EPA has no adequate answer for that failure.

Wisconsin. Wisconsin's 2012 baseline included generation from a zero-carbon emitting nuclear facility (the Kewaunee plant) that retired in 2013. EPA knew of the retirement and that the plant represented approximately 7.3% of Wisconsin's total generation in 2012. *See* Wisconsin Dep't of Natural Resources Comments, EPA-HQ-OAR-2013-0602-23541 at 1, 4, JA1918, JA1921. EPA nonetheless disregarded Kewaunee's retirement in setting Wisconsin's baseline, arguing it acted consistently when it declined to make adjustments for *all* retirements after the baseline year. EPA Br. 168. But retirements of fossil units presumably aid compliance in a State because such units are generally the older, higher-emitting ones. On the other hand, when a zero-emission unit is retired, the State's compliance task becomes much harder. EPA allowed adjustments and allocations of credits for retirements of zero-emitting hydroelectric sources for precisely this reason. 80 Fed. Reg. at 64,815, JA296. There is no rational basis for treating the retirement of non-emitting nuclear units differently.

Utah. EPA improperly set Utah's 2030 mass-based emissions target approximately 2,500,000 tons *below* what it should have been based on Utah's historic emissions. The 2012 emissions data do not account for a five-month outage of the Intermountain Power Plant. Record Br. 77-79.

EPA contends Utah was not entitled to an adjustment because the failure did not meet EPA's two-part test "for outlier events causing exceptional distortions in the baseline year" and that Utah did "not challenge the reasonableness of EPA's adjustment criteria for unit outages, or the factual basis for EPA's determination that the criteria were not met." EPA Br. 170.

Utah could not challenge EPA's methodology because EPA only disclosed it in the final Rule. Moreover, Utah's arguments cannot fairly be read as anything *other than* a challenge to the reasonableness of EPA's adjustment methodology. Record Br. 77-78. An adjustment formula that does not account for a five-month mechanical failure at a State's largest power plant—which produces almost one-third of the electricity generated there—is arbitrary and capricious.

EPA also assumed Utah could reduce its coal-fired emissions by increasing electrical generation at its four gas-fired plants. This directly conflicts with Utah's commitment in its existing state implementation plan to *reduce* production at these gas-fired plants. EPA is requiring Utah to meet conflicting regulatory goals and obligations, *see* Utah Comments 15, JA1318, where one regulatory objective can be advanced only to the detriment of the other.

Arizona/Utah Tribes. EPA failed to account for the unique challenges facing Utah and Arizona, given their heavy reliance on power generated on tribal lands subject to federal jurisdiction. Contrary to EPA's assertions, EPA Br. 173, the Rule's failure to allow trading of emission credits and allowances between rate- and mass-based States and sovereigns is ripe for review because it presents a purely legal question—whether EPA's final action is arbitrary, capricious, and imposes unlawful hardship on States that have substantial amounts of their energy produced on tribal lands. *Energy Future Coal. v. EPA*, 793 F.3d 141, 146 (D.C. Cir. 2015).[14]

Wyoming. EPA failed to account for unique species concerns in Wyoming, such as the sage grouse corridor, which makes the development of new renewable resources extremely challenging. Record Br. 75-76. EPA has not responded in any way to this argument.

EPA also improperly conflated this argument with the concern of Wyoming and North Dakota that EPA failed to consult *nationally* under the Endangered Species Act ("ESA").[15] *Id.* at 76-77. EPA's response relies entirely on an inapposite decision. EPA Br. 171-73 (citing *Ctr. For Biological Diversity v. Dep't of the Interior*, 563 F.3d 466 (D.C. Cir. 2009) ("*CBD*")). In *CBD*, this Court found a delay in consultation appropriate because the Interior Department had committed to ESA consultation *at a*

[14] Petitioners are not challenging the proposed federal plan. They challenge the arbitrary hardship created by *this* Rule, which exists *regardless* of how EPA finalizes its proposed federal plan. It is "unnecessary to wait for EPA's legal conclusion to be applied in order to determine its legality." *Energy Future Coal.*, 793 F.3d at 146 (internal quotations omitted).

[15] This argument is advanced solely by Wyoming and North Dakota.

later stage in the leasing process and because it was uncertain whether that leasing program would affect any listed species. 563 F.3d at 482. Here, EPA made no such commitment to consult at some later time, 80 Fed. Reg. at 64,925-27, JA406-08, although it expressly acknowledged the Rule (which will force the development of new wind and solar generation) is likely to affect listed species, *id.* at 64,926, JA407. EPA was required to consult under the ESA but failed to do so.

New Jersey. EPA failed to consider States like New Jersey that have deregulated energy services and do not regulate electricity generation. Record Br. 80-82. To comply with the Rule, the New Jersey Board of Public Utilities would need new statutory authority to direct existing units' actions, integrate the responsibilities of environmental and public utility regulators, or develop a trading program. *Id.* at 81.

CONCLUSION

The petitions should be granted and the Rule vacated.

Dated: April 22, 2016 Respectfully submitted,

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CERTIFICATE OF COMPLIANCE

Pursuant to Rule 32(a)(7)(C) of the Federal Rules of Appellate Procedure and Circuit Rules 32(e)(1) and 32(e)(2)(C), I hereby certify that the foregoing Reply Brief of Petitioners on Procedural and Record-Based Issues contains 8,481 words, as counted by a word processing system that includes headings, footnotes, quotations, and citations in the count, and therefore is within the word limit set by the Court.

Dated: April 22, 2016

/s/ Thomas A. Lorenzen
Thomas A. Lorenzen

CERTIFICATE OF SERVICE

I hereby certify that, on this 22nd day of April 2016, a copy of the foregoing Reply Brief of Petitioners on Procedural and Record-Based Issues was served electronically through the Court's CM/ECF system on all ECF-registered counsel.

/s/ Thomas A. Lorenzen
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ATTACHMENT

Redline of Regulatory Language

(Comparing Proposed and Final Rule Regulatory Language)

For the reasons stated in the preamble, title 40, chapter I, part 60 of the Code of the Federal Regulations is ~~proposed to be~~ amended as follows:

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

■ 1. The authority citation for Part 60 continues to read as follows:

Authority: 42 U.S.C. 7401 *et seq.*

■ 2. ~~Section 60.27 is amended by revising paragraph (b)~~Add subpart UUUU to read as follows:

~~**§ 60.27 Actions by the Administrator.**~~

~~* * * * * (b) After receipt of a plan or plan revision, the Administrator will propose the plan or revision for approval or disapproval. The Administrator will, within four months after the date required for submission of a plan or plan revision, approve or disapprove such plan or revision or each portion thereof, except as provided in § 60.5715.~~

~~* * * * * ■ 3. Add subpart UUUU to read as follows:~~

Subpart—UUUU~~:~~ Emission Guidelines for Greenhouse Gas Emissions and Compliance Times for Electric Utility Generating Units

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Table 3 to Subpart UUUU of Part 60— Statewide Mass-based CO2 Emission Goals (Short Tons of CO2)

Table 4 to Subpart UUUU of Part 60— Statewide Mass-based CO2 Emission Goals plus New Source CO2 Emission Complement (Short Tons of CO2)

Introduction

§ 60.5700 What is the purpose of this subpart?

This subpart establishes emission guidelines and approval criteria for ~~state~~State or multi-State plans that establish emission standards limiting ~~the control of~~ greenhouse gas (GHG) emissions from an affected steam generating unit, integrated gasification combined cycle (IGCC), or stationary combustion turbine. An affected steam generating unit, IGCC, or stationary combustion turbine shall, for the purposes of this subpart, be referred to as an affected EGU. These emission guidelines are developed in accordance with ~~sections~~section 111(d) of the Clean Air Act and subpart B of this part. To the extent any requirement of this subpart is inconsistent with the requirements of subparts A or B of this part, the requirements of this subpart will apply.

§ 60.5705 ~~What~~Which pollutants are regulated by this subpart?

~~(a) The pollutants regulated by this subpart are greenhouse gases.~~

(~~b~~a) The ~~greenhouse gas~~pollutants regulated by this subpart ~~is~~are greenhouse gases. The emission guidelines for greenhouse gases established in this subpart are expressed as carbon dioxide (CO_2) emission performance rates and equivalent statewide CO_2 emission goals.

(b) PSD and Title V Thresholds for Greenhouse Gases.

(1) For the purposes of

§ 51.166(b)(49)(ii), with respect to GHG emissions from facilities, the "pollutant that is subject to the standard promulgated under section 111 of the Act" shall be considered to be the pollutant that otherwise is subject to regulation under the Act as defined in

§ 51.166(b)(48) and in any State Implementation Plan (SIP) approved by the EPA that is interpreted to incorporate, or specifically incorporates, § 51.166(b)(48) of this chapter.

(2) For the purposes of

§ 52.21(b)(50)(ii), with respect to GHG emissions from facilities regulated in the plan, the "pollutant that is subject to the standard promulgated under section 111 of the Act" shall be considered to be the pollutant that otherwise is subject to regulation under the Act as defined in § 52.21(b)(49) of this chapter.

(3) For the purposes of § 70.2 of this chapter, with respect to greenhouse gas emissions from facilities regulated in the plan, the "pollutant that is subject to any standard promulgated under section 111 of the Act" shall be considered to be the pollutant that otherwise is "subject to regulation" as defined in § 70.2 of this chapter.

(4) For the purposes of § 71.2, with respect to greenhouse gas emissions from facilities regulated in the plan, the "pollutant that is subject to any standard promulgated under section

111 of the Act" shall be considered to be the pollutant that otherwise is "subject to regulation" as defined in § 71.2 of this chapter.

§ 60.5710 Am I affected by this subpart?

~~If you are the Administrator of an air quality program in a state with one or~~

If you are the Governor of a State in the contiguous United States with one or more affected EGUs that commenced construction on or before January 8, 2014, you must submit a ~~state~~State or multi-State plan to the U.S. Environmental Protection Agency (EPA) that implements the emission guidelines contained in this subpart. ~~You must submit a negative declaration letter in place of the state plan if there are~~If you are the Governor of a State in the contiguous United States with no affected EGUs for which construction commenced on or before January 8, 2014, in your ~~state~~State, you must submit a negative declaration letter in place of the State plan.

§ 60.5715 What is the review and approval process for my ~~state~~ plan?

The EPA will review your ~~state~~ plan according to § 60.27 except that under § 60.27(b) the Administrator will have ~~twelve~~12 months after the date ~~required for submission of a~~the final plan or plan revision (as allowed under § 60.5785) is submitted, to approve or disapprove such plan or revision or each portion thereof. If you submit ~~a request for extension~~an initial submittal under § ~~60.5760~~60.5765(a) in lieu of a ~~complete state~~final plan submittal the EPA will follow the procedure in § ~~60.5760~~60.5765(b).

§ 60.5720 What if I do not submit a plan or my plan is not approvable?

(a) If you do not submit an approvable ~~state~~ plan the EPA will develop a Federal plan for your ~~state~~State according to § 60.27 ~~to~~. The Federal plan will implement the emission guidelines contained in this subpart. Owners and operators of affected ~~entities~~EGUs not covered by an approved ~~state~~ plan must comply with a Federal plan implemented by the EPA for the ~~state~~State. ~~The~~

(b) After a Federal plan ~~is an interim action and will be automatically~~has been implemented in your State, it will be withdrawn when your ~~state~~State submits, and the EPA approves, a final plan ~~is approved~~.

§ 60.5725 In lieu of a ~~state~~State plan submittal, are there other acceptable option(s) for a ~~state~~State to meet its CAA section 111(d) obligations?

A ~~state~~State may meet its CAA section 111(d) obligations only by submitting a ~~complete state~~final State or multi-State plan submittal or a negative declaration letter (if applicable).

§ 60.5730 Is there an approval process for a negative declaration letter?

No. The EPA has no formal review process for negative declaration letters. Once your negative declaration letter has been received, the EPA will place a copy in the public docket and publish a notice in the **Federal Register**. If, at a later date, an affected EGU for which construction commenced on or before January 8, 2014 is found in your ~~state,~~State, you will be found to have failed to submit a final plan as required, and a Federal plan implementing the emission guidelines contained in this subpart ~~would automatically~~, when promulgated by the EPA, will apply to that affected EGU until ~~your state~~you submit, and the EPA approves, a final State plan ~~is approved~~.

§ 60.5735 What authorities will not be delegated to ~~state~~State, local, or tribal agencies?

The authorities that will not be delegated to State, local, or tribal agencies are specified in ~~paragraph~~paragraphs (a) and (b) of this section.

(a) Approval of alternatives, not already approved by this subpart, to the ~~emissions~~CO2 emission performance ~~goals~~rates in Table 1 to this subpart established under § 60.5855. ~~§ 60.5755.~~

~~(b) [Reserved]~~

~~State Plan~~

(b) Approval of alternatives, not already approved by this subpart, to the CO2 emissions goals in Tables 2, 3 and 4 to this subpart established under § 60.5855.

§ 60.5736 Will the EPA impose any sanctions?

No. The EPA will not withhold any existing federal funds from a State on account of a State's failure to submit, implement, or enforce an approvable plan or plan revision, or to meet any other requirements under this subpart or subpart B of this part.

§ 60.5737 What is the Clean Energy Incentive Program and how do I participate?

(a) This subpart establishes the Clean Energy Incentive Program (CEIP). Participation in this program is optional. The program enables States to award early action emission rate credits (ERCs) and allowances to eligible renewable energy (RE) or demand-side energy efficiency (EE) projects that generate megawatt hours (MWh) or reduce end-use energy demand during 2020 and/or 2021. Eligible projects are those that:

(1) Are located in or benefit a state that has submitted a final state plan that includes requirements establishing its participation in the CEIP; and

(2) Commence construction in the case of RE, or commence operation in the case of demand-side EE, following the submission of a final state plan to the EPA, or after September 6, 2018 for a state that chooses not to submit a final state plan by that date; and either

(3) Generate metered MWh from any type of wind or solar resources; or

(4) Result in quantified and verified electricity savings (MWh) through demand-side EE implemented in low-income communities.

(b) The EPA will award matching ERCs or allowances to States that award early action ERCs or allowances, up to a match limit equivalent to 300 million tons of CO2 emissions. The awards will be executed as follows:

(1) For RE projects that generate metered MWh from wind or solar resources: For every two MWh generated, the project will receive one early action ERC (or the equivalent number of allowances) from the State, and the EPA will provide one matching ERC (or the equivalent number of allowances) to the State to award to the project.

(2) For EE projects implemented in low-income communities: For every two MWh in end-use demand savings achieved, the project will receive two early action ERCs (or the equivalent number of allowances) from the State, and the EPA will provide two matching ERCs (or the equivalent number of allowances) to the State to award to the project.

(c) You may participate in this program by including in your State plan a mechanism that enables issuance of early action ERCs or allowances by the State to parties effectuating reductions in the calendar years 2020 and/or 2021 in a manner that would have no impact on the emission performance of affected EGUs required to meet rate-based or mass-based emission standards during the performance periods. This mechanism is not required to account for matching ERCs or allowances that may be issued to the State by the EPA.

(d) If you are submitting an initial submittal by September 6, 2016, and you intend to participate in the CEIP, you must include a non-binding statement of intent to participate in the program. If you are submitting a final plan by September 6, 2016, and you intend to participate in the CEIP, your State plan must either include requirements establishing the necessary infrastructure to implement such a program and authorizing your affected EGUs to use early action allowances or ERCs as appropriate, or you must include a non-binding statement of intent as part of your supporting documentation and revise your plan to include the appropriate requirements at a later date.

(e) If you intend to participate in the CEIP, your final State plan, or plan revision if applicable, must require that projects eligible under this program be evaluated, monitored, and verified, and that resulting ERCs or allowances be issued, per applicable requirements of the State plan approved by the EPA as meeting § 60.5805 through § 60.5835.

State and Multi-State Plan Requirements

§ 60.5740 What must I include in my ~~state~~federally enforceable State or multi State plan?

~~(a) You must include the elements described in paragraphs (a)(1) through (11) of this section in your state plan.~~

(a) You must include the components described in paragraphs (a)(1) through (5) of this section in your plan submittal. The final plan must meet the requirements and include the information required under § 60.5745.

(1) *Identification of affected* ~~entities, including~~*EGUs.* Consistent with § 60.25(a), you must identify the affected EGUs covered by your plan and all affected EGUs in your State that meet the applicability criteria in § 60.5845. In addition, you must include an inventory of CO2

emissions from the affected EGUs during the most recent calendar year for which data is available prior to the submission of the plan ~~for which data is available~~.

~~(2) A description of plan approach and the geographic scope of a plan (state or multi-state), including, if relevant, identification of multi-state plan participants and geographic boundaries related to plan elements.~~

~~(3) Identification of the state emission performance level for affected entities that will be achieved through implementation of the plan.~~

~~(i) The plan must specify the average emissions performance that the plan will achieve for the following periods:~~

~~(A) The 10 year interim plan performance period of 2020 through 2029.~~

~~(B) The single projection year of 2030.~~

(2) *Emission standards.* You must include an identification of all emission standards for each affected EGU according to § 60.5775, compliance periods for each emission standard according to § 60.5770, and a demonstration that the emission standards, when taken together, achieve the applicable CO2 emission performance rates or CO2 emission goals described in § 60.5855. Allowance systems are an acceptable form of emission standards under this subpart.

(i) Your plan does not need to include corrective measures specified in paragraph (a)(2)(ii) of this section if your plan:

(A) Imposes emission standards on all affected EGUs that, assuming full compliance by all affected EGUs, mathematically assure achievement of the CO2 emission performance rates in the plan for each plan period;

(B) Imposes emission standards on all affected EGUS that, assuming full compliance by all affected EGUs, mathematically assure achievement of the CO2 emission goals; or

(C) Imposes emission standards on all affected EGUs that, assuming full compliance by all affected EGUs, in conjunction with applicable requirements under state law for EGUs subject to subpart TTTT of this subpart, assuming the applicable requirements under state law are met by all EGUs subject to subpart TTTT of this subpart, achieve the applicable mass-based CO2 emission goals plus new source CO2 emission complement allowed for in § 60.5790(b)(5).

(ii) ~~The identified emission performance level for each plan performance period in paragraph~~If your plan does not meet the requirements of (a)(~~3~~2)(i) or (iii) of this section, your plan must ~~be equivalent to or better than the levels of the rate-based~~include the requirement for corrective measures to be implemented if triggered. Upon triggering corrective measures, if you do not already have them included in your approved State plan, you must submit corrective measures to EPA for approval as a plan revision per the requirements of § 60.5785(c). These corrective measures must ensure that the interim period and final period CO2 emission performance ~~goals in Table 1 of this Subpart for affected entities in your state. The~~rates or CO2 emission goals are achieved by your affected EGUs, as applicable, and must achieve additional emission reductions to offset any emission performance ~~levels may be in either a rate-based form or a mass based form which is calculated according to § 60.5770. The~~shortfall. Your plan must include the requirement that corrective measures be triggered and implemented according to paragraphs (a)(2)(ii)(A) through (H) of this section.

(A) Your plan must include a trigger for an exceedance of an interim step 1 or interim step 2 CO2 emission performance ~~level specified must include either of the following as~~rate or CO2 emission goal by 10 percent or greater, either on average or cumulatively (if applicable~~:~~).

(B) Your plan must include a trigger for an exceedance of an interim step 1 goal or interim step 2 goal of 10 percent or greater based on either reported CO2 emissions with applied plus or minus net allowance export or import adjustments (if applicable), or based on the adjusted CO2 emission rate (if applicable).

(C) Your plan must include a trigger for a failure to meet an interim period goal based on reported CO2 emissions with applied plus or minus net allowance export or import adjustments

~~(A) For a rate-based CO2 emission performance level, the identified level must represent the CO2 emissions rate, in pounds of CO2 per MWh of net energy output that will be achieved by affected entities.~~

~~(B) For a mass-based CO2 emission performance level, the identified level of performance must represent the total tons of CO2 that will be emitted by affected entities during each plan performance period.~~

~~(iii) For the interim plan performance period you must identify the emission performance levels anticipated under the plan during each year 2020 through 2029.~~

~~(4) A demonstration that the plan is projected to achieve each of the state's emission performance levels for affected entities according to paragraph (a)(3) of this section.~~

~~(5) Identification of emission standards for each affected entity, compliance periods for each emission standard, and demonstration that the emission standards are, when taken together, sufficiently protective to meet the state emissions performance level.~~

~~(6) A demonstration that each emission standard is quantifiable, non-duplicative, permanent, verifiable, and enforceable with respect to an affected entity.~~

(if applicable), or based on the adjusted CO2 emission rate (if applicable).

(D) Your plan must include a trigger for a failure to meet the interim period or any final reporting period CO2 emission performance rate or CO2 emission goal, either on average or cumulatively (as applicable).

(E) Your plan must include a trigger for a failure to meet any final reporting period goal based on reported CO2 emissions with applied plus or minus net allowance export or import adjustments (if applicable).

(F) Your plan must include a trigger for a failure to meet the interim period CO2 emission performance rate or CO2 emission goal based on the adjusted CO2 emission rate (if applicable).

(G) Your plan must include a trigger for a failure to meet any final reporting period CO2 emission performance rate or CO2 emission goal based on the adjusted CO2 emission rate (if applicable).

(H) A net allowance import adjustment represents the CO2 emissions (in tons) equal to the number of net imported CO2 allowances. This adjustment is subtracted from reported CO2 emissions. Under this adjustment, such allowances must be issued by a state with an emission budget trading program that only applies to affected EGUs (or affected EGUs plus EGUs covered by subpart TTTT of this part as applicable). A net allowance export adjustment represents the CO2 emissions (in tons) equal to the number of net exported CO2 allowances. This adjustment is added to reported CO2 emissions.

(~~7~~iii) If your ~~state~~ plan ~~does not require achievement of the full level of required emission performance, and the identified interim increments of performance~~relies upon State measures, in addition to or in lieu of emission standards on your affected EGUs, then the final State plan must include the requirements in paragraph (a)(3)~~(iii)~~ of this section~~, through emission limits on EGUs, the plan must specify the following:~~ and the submittal must include the information listed in § 60.5745(a)(6).

~~(i) Program implementation milestones (e.g., start of an end-use energy efficiency program, retirement of an affected EGU, or increase in portfolio requirements under a renewable portfolio standard) and milestone dates that are appropriate to the requirements, programs, and measures included in the plan.~~

~~(ii) Corrective measures that will be implemented in the event that the comparison required by § 60.5815(b) of projected versus actual emissions performance of affected entities shows that actual emissions performance is greater than 10 percent in excess to projected plan performance for the period described in § 60.5775(c)(1), and a process and schedule for implementing such corrective measures.~~

(iv) If your plan requires emission standards in addition to relying upon State measures, then you must demonstrate that the emission standards and State measures, when taken together, result in the achievement of the applicable mass-based CO2 emission goal described in § 60.5855 by your State's affected EGUs.

(3) *State measures backstop.* If your plan relies upon State measures, you must submit, as part of the plan in lieu of the requirements in paragraph (a)(2)(i) and (ii) of this section, a federally enforceable backstop that includes emission standards for affected EGUs that will be put into place, if there is a triggering event listed in paragraph (a)(3)(i) of this section, within 18 months of the due

date of the report required in § 60.5870(b). The emission standards on the affected EGUs as part of the backstop must be able to meet either the CO2 emission performance rates or mass-based or rate-based CO2 emission goal for your State during the interim and final periods. You must either submit, along with the backstop emission standards, provisions to adjust the emission standards to make up for the prior emission performance shortfall, such that no later plan revision to modify the emission standards is necessary in order to address the emission performance shortfall, or you must submit, as part of the final plan, backstop emission standards that assure affected EGUs would achieve your State's CO2 emission performance rates or emission goals during the interim and final periods, and then later submit appropriate revisions to the backstop emission standards adjusting for the shortfall through the State plan revision process described in § 60.5785. The backstop must also include the requirements in paragraphs (a)(3)(i) through (iii) of this section, as applicable.

(i) You must include a trigger for the backstop to go into effect upon:

(A) A failure to meet a programmatic milestone;

(B) An exceedance of 10 percent or greater of an interim step 1 goal or interim step 2 goal based on reported CO2 emissions, with applied plus or minus net allowance export or import adjustments (if applicable);

(C) A failure to meet the interim period goal based on reported CO2 emissions, with applied plus or minus net allowance export or import adjustments (if applicable); or

(D) A failure to meet any final reporting period goal based on reported CO2 emissions, with applied plus or minus net allowance export or import adjustments (if applicable).

(ii) You may include in your plan any additional triggers so long as they do not reduce the stringency of the triggers required under paragraph (a)(3)(i) of this section.

(iii) You must include a schedule for implementation of the backstop once triggered, and you must identify all necessary State administrative and technical procedures for implementing the backstop.

(~~8~~4) *Identification of applicable monitoring, reporting, and recordkeeping requirements for each affected* ~~entity. If~~*EGU.* You must include in your plan all applicable~~, these requirements must be~~

~~**consistent with the requirements specified in § 60.5810.**~~ **monitoring, reporting and recordkeeping requirements for each affected EGU and the requirements must be consistent with or no less stringent than the requirements specified in § 60.5860.**

(~~9~~5) ~~**Description**~~***State reporting.*** **You must include in your plan a description** of the process, contents, and schedule for ~~**annual state**~~State reporting to the EPA about plan implementation and progress, including information required under § ~~**60.5815**~~60.5870.

(i) You must include in your plan a requirement for a report to be submitted by July 1, 2021, that demonstrates that the State has met, or is on track to meet, the programmatic milestone steps indicated in the timeline required in § 60.5770.

(b) You must follow the requirements of subpart B of this part and demonstrate that they were met in your State plan. However, the provisions of § 60.24(f) shall not apply.

§ 60.5745 What must I include in my final plan submittal?

(a) In addition to the components of the plan listed in § 60.5740, a final plan submittal to the EPA must include the information in paragraphs (a)(1) through (13) of this section. This information must be submitted to the EPA as part of your final plan submittal but will not be codified as part of the federally enforceable plan upon approval by EPA.

(1) You must include a description of your plan approach and the geographic scope of the plan (*i.e.,* State or multi-State, geographic boundaries related to the plan elements), including, if applicable, identification of multi-State plan participants.

(2) You must identify CO_2 emission performance rates or equivalent statewide CO_2 emission goals that your affected EGUs will achieve. If the geographic scope of your plan is a single State, then you must identify CO_2 emission performance rates or emission goals according to § 60.5855. If your plan includes multiple States and you elect to set CO_2 emission goals, you must identify CO_2 emission goals calculated according to § 60.5750.

(i) You must specify in the plan submittal the CO_2 emission performance rates or emission goals that affected EGUs will meet for the interim period, each interim step, and the final period (including each final reporting period) pursuant to § 60.5770.

(ii) [Reserved]

(3) You must include a demonstration that the affected EGUs covered by the plan are projected to achieve the CO_2 emission performance rates or CO_2 emission goals described in § 60.5855.

(4) You must include a demonstration that each affected EGU's emission standard is quantifiable, non-duplicative, permanent, verifiable, and enforceable according to § 60.5775.

(5) If your plan includes emission standards on your affected EGUs sufficient to meet either the CO_2 emission performance rates or CO_2 emission goals, you must include in your plan submittal the information in paragraphs (a)(5)(i) through (v) of this section as applicable.

(i) If your plan applies separate rate-based CO_2 emission standards for affected EGUs (in lbs CO_2/MWh) that are equal to or lower than the CO_2 emission performance rates listed in Table 1 of this subpart or uniform rate-based CO_2 emission standards equal to or lower than the rate-based CO_2 emission goals listed in Table 2 of this subpart, then no additional demonstration is required beyond inclusion of the emission standards in the plan.

(ii) If a plan applies rate-based emission standards to individual affected EGUs at a lbs CO_2/MWh rate that differs from the CO_2 emission performance rates in Table 1 of this subpart or the State's rate-based CO_2 emission goal in Table 2 of this subpart, then a further demonstration is required that the application of the CO_2 emission standards will achieve the CO_2 emission performance rates or State rate-based CO_2 emission goal. You must demonstrate through a projection that the adjusted weighted average CO_2 emission rate of affected EGUs, when weighted by generation (in MWh), will be equal to or less than the CO_2 emission performance rates or the rate-based CO_2 emission goal. This projection must address the interim period and the final period. The projection in the plan submittal must include the information listed in paragraph (a)(5)(v) of this section and in addition the following:

(A) An analysis of the change in generation of affected EGUs given the compliance costs and incentives under the application of different emission rate standards across affected EGUs in a State;

(B) A projection showing how generation is expected to shift between affected EGUs and across affected EGUs and non-affected EGUs over time;

(C) Assumptions regarding the availability and anticipated use of the MWh of electricity generation or electricity savings from eligible resources that can be issued ERCs;

(D) The specific calculation (or assumption) of how eligible resource MWh of electricity generation or savings are being used in the projection to adjust the reported CO2 emission rate of affected EGUs;

(E) If a state plan provides for the ability of renewable energy resources located in states with mass-based plans to be issued ERCs, consideration in the projection that such resources must meet geographic eligibility requirements, consistent with § 60.5800(a); and

(F) Any other applicable assumptions used in the projection.

(iii) If a plan establishes mass-based emission standards for affected EGUs that cumulatively do not exceed the State's EPA-specified mass CO2 emission goal, then no additional demonstration is required beyond inclusion of the emission standards in the plan.

(iv) If a plan applies mass-based emission standards to individual affected EGUs that cumulatively exceed the State's EPA-specified mass CO2 emission goal, then you must include a demonstration that your mass-based emission program will be designed such that compliance by affected EGUs would achieve the State mass-based CO2 emission goals. This demonstration includes the information listed in paragraph (a)(5)(v) of this section.

(v) Your plan demonstration to be included in your plan submittal, if applicable, must include the information listed in paragraphs (a)(5)(v)(A) through (L) of this section.

(A) A summary of each affected EGU's anticipated future operation characteristics, including:

(1) Annual generation;

(2) CO2 emissions;

(3) Fuel use, fuel prices (when applicable), fuel carbon content;

(4) Fixed and variable operations and maintenance costs (when applicable);

(5) Heat rates; and

(6) Electric generation capacity and capacity factors.

(B) An identification of any planned new electric generating capacity.

(C) Analytic treatment of the potential for building unplanned new electric generating capacity.

(D) A timeline for implementation of EGU-specific actions (if applicable).

(E) All wholesale electricity prices.

(F) A geographic representation appropriate for capturing impacts and/ or changes in the electric system.

(G) A time period of analysis, which must extend through at least 2031.

(H) An anticipated electricity demand forecast (MWh load and MW peak demand) at the State and regional level, including the source and basis for these estimates, and, if appropriate, justification and documentation of underlying assumptions that inform the development of the demand forecast (e.g., annual economic and demand growth rate or population growth rate).

(I) A demonstration that each emission standard included in your plan meets the requirements of § 60.5775.

(J) Any ERC or emission allowance prices, when applicable.

(K) An identification of planning reserve margins.

(L) Any other applicable assumptions used in the projection.

(6) If your plan relies upon State measures, in addition to or in lieu of the emission standards required by paragraph § 60.5740(a)(2), the final State plan submittal must include the information under paragraphs (a)(5)(v) and (a)(6)(i) through (v) of this section.

(i) You must include a description of all the State measures the State will rely upon to achieve the applicable CO2 emission goals required under

§ 60.5855(e), the projected impacts of the State measures over time, the applicable State laws or regulations related to such measures, and identification of parties or entities subject to or implementing such State measures.

(ii) You must include the schedule and milestones for the implementation of the State measures. If the State measures in your plan submittal rely upon measures that do not have a direct effect on the CO2 emissions measured at an affected EGU's stack, you must also demonstrate how the minimum emission, monitoring and verification (EM&V) requirements listed under § 60.5795 that apply to those programs and projects will be met.

(iii) You must demonstrate that federally enforceable emission standards for affected EGUs in conjunction with any State measures relied upon for your plan, are sufficient to achieve the mass-based CO2 emission goal for the interim period, each interim step in that interim period, the final period, and each final reporting period. In addition, you must demonstrate that each emission standard included in your plan meets the requirements of § 60.5775 and each State measure included in your plan submittal meets the requirements of § 60.5780.

(iv) You must include a CO2 performance projection of your State measures that shows how the measures, whether alone or in conjunction with any federally enforceable CO2 emission standards for affected EGUs, will result in the achievement of the future CO2 performance at affected EGUs. Elements of this projection must include those specified in paragraph (a)(5)(v) of this section, as applicable, and the following for the interim period and the final period:

(A) A baseline demand and supply forecast as well as the underlying assumptions and data sources of each forecast;

(B) The magnitude of energy and emission impacts from all measures included in the plan and applicable assumptions;

(C) An identification of State-enforceable measures with electricity savings and RE generation, in MWh, expected for individual and collective measures and any assumptions related to the quantification of the MWh, as applicable.

(7) Your plan submittal must include a demonstration that the reliability of the electrical grid has been considered in the development of your plan.

(8) Your plan submittal must include a timeline with all the programmatic milestone steps the State intends to take between the time of the State plan submittal and January 1, 2022 to ensure the plan is effective as of January 1, 2022.

(9) Your plan submittal must adequately demonstrate that your State has the legal authority (e.g., through regulations or legislation) and funding to implement and enforce each component of the State plan submittal, including federally enforceable emission standards for affected EGUs, and State measures as applicable.

(10) Your State plan submittal must demonstrate that each interim step goal required under § 60.5855(c), will be met and include in its supporting documentation, if applicable, a description of the analytic process, tools, methods, and assumptions used to make this demonstration.

(~~10) Certification that the~~11) Your plan submittal must include certification that a hearing required under § 60.23(c)(1) on the ~~state~~State plan was held, a list of witnesses and their organizational affiliations, if any, appearing at the hearing, and a brief written summary of each presentation or written submission, pursuant to the requirements of § 60.23(d) and (f).

(12) Your plan submittal must include documentation of any conducted community outreach and community involvement, including engagement with vulnerable communities.

(~~11) Supporting~~13) Your plan submittal must include supporting material for your plan including:

(i) Materials demonstrating the ~~state's~~State's legal authority ~~to carry out~~and funding to implement and enforce each component of its plan, including emissions standards and/or State measures that the plan relies upon;

(ii) Materials supporting that the ~~projected emissions~~CO2 emission performance ~~level that~~rates or CO2 emission goals will be achieved by

affected ~~entities~~EGUs identified under the plan, according to paragraph (a)(~~4~~3) of this section;

(iii) Materials supporting ~~the projected mass-based~~any calculations for CO2 emission ~~performance goal,~~goals calculated ~~pursuant~~according to § ~~60.5770~~60.5855, if applicable; and

(iv) ~~Materials~~Any other materials necessary to support evaluation of the plan by the EPA.

(b) You must ~~follow the requirements of subpart B of this part (Adoption and Submittal of state plans for Designated Facilities) and demonstrate that they were met in your state plan~~submit your final plan to the EPA electronically according to § 60.5875.

§ ~~60.5745~~60.5750 Can I work with other ~~states~~States to develop a ~~multi-state~~multi-State plan?

A multi-State plan must include all the required elements for a plan specified in § 60.5740(a). A multi-State plan must meet the requirements of paragraphs (a) and (b) of this section.

(a) The multi-State plan must demonstrate that all affected EGUs in all participating States will meet the CO2 emission performance rates listed in Table 1 of this subpart or an equivalent CO2 emission goal according to paragraphs (a)(1) or (2) of this section. States may only follow the procedures in (a)(1) or (2) if they have functionally equivalent requirements meeting § 60.5775 and § 60.5790 included in their plans.

~~A multi-state plan may be submitted, provided it is signed by authorized officials for each of the states participating in the multi-state plan. In this instance, the joint submittal will have the same legal effect as an individual submittal for each participating state. A multi-state plan will include all the required elements for a single-state plan specified in § 60.5740(a). A multi-state plan, if submitted by a state, must:~~

~~(a) Demonstrate CO2 emission performance jointly for all affected entities in all states participating in the multi-state plan, as follows:~~

~~(1) For states demonstrating~~

(1) For States electing to demonstrate performance ~~based on the~~with a CO2 emission ~~rate, the level of performance~~rate-based goal, the CO2 emission goals identified in the ~~multi-state~~ plan ~~pursuant~~according to § ~~60.5740(a)(3)~~60.5855 will be ~~a~~an adjusted weighted (by net energy output)

average ~~lb~~lbs CO2/ MWh emission rate to be achieved by all affected EGUs in the ~~multi-state~~multi-State area during the plan ~~performance period~~periods; or

(2) For ~~states demonstrating performance based on~~States electing to demonstrate performance with a CO2 emission mass-based goal, the CO2 emission goals identified in the multi-State plan according to § 60.5855 will be total mass CO2 emissions~~, the level of performance identified in the multi-state plan pursuant to 60.5740(a)(3) will be total CO2 emissions~~ by all affected EGUs in the ~~multi-state~~multi-State area during the plan ~~performance period~~periods, representing the sum of all individual mass CO2 goals for states participating in the multi-state plan.

~~(b) Assign among states, according to a formula in the multi-state plan, avoided CO2 emissions resulting from emission standards contained in the plan, from affected entities in states participating in the multi-state plan.~~

~~**§ 60.5750 Can I include existing requirements, programs, and measures in my state plan?**~~

~~(a) Yes, you may include existing requirements, programs and measures in your plan according to paragraphs (b) through (d) of this section.~~

~~(b) Existing state programs, requirements, and measures, may qualify for use in demonstrating that a state plan achieves the required level of emission performance specified in a plan, according to § 60.5740(a)(3).~~

(b) Options for submitting a multi-State plan include the following:

(1) States participating in a multi-State plan may submit one multi-State plan submittal on behalf of all participating States. The joint submittal must be signed electronically, according to § 60.5875, by authorized officials for each of the States participating in the multi-State plan. In this instance, the joint submittal will have the same legal effect as an individual submittal for each participating State. The joint submittal must address plan components that apply jointly for all participating States and components that apply for each individual State in the multi-State plan, including necessary State legal authority to implement the plan, such as State regulations and statutes.

(2) States participating in a multi-State plan may submit a single plan submittal, signed by authorized officials from each participating State, which addresses common plan elements. Each participating State must, in addition, provide individual plan submittals that address State-specific elements of the multi-State plan.

(3) States participating in a multi-State plan may separately make individual submittals that address all elements of the multi-State plan. The plan submittals must be materially consistent for all common plan elements that apply to all participating States, and also must address individual State-specific aspects of the multi-State plan. Each individual State plan submittal must address all required plan components in § 60.5740.

(c) ~~Existing state programs, requirements, and measures, may qualify for use in projecting that a state plan will achieve the required level of emission performance specified in a plan, according to § 60.5740(a)(4).~~A State may elect to participate in more than one multi-State plan. If your State elects to participate in more than one multi-State plan then you must identify in the State plan submittal required under § 60.5745, the subset of affected EGUs that are subject to the specific multi-State plan or your State's individual plan. An affected EGU can only be subject to one plan.

(d) A State may elect to allow its affected EGUs to interact with affected EGUs in other States through mass-based trading programs or a rate-based trading program without entering into a formal multi-State plan allowed for under this section, so long as such programs are part of an EPA-approved state plan and meet the requirements of paragraphs (d)(1) and (2) of this section, as applicable.

~~(d) Emission impacts of existing programs, requirements, and measures that occur during a plan performance period may be recognized in meeting or projecting CO2 emission performance by affected EGUs according to § 60.5740(a)(3) and (4), as long as they meet the following requirements:~~

(1) ~~Actions taken pursuant to an existing state program, requirement, or measure, such as compliance with a regulatory obligation or initiation of an action related to a program or measure, must occur after June 18, 2014; and~~For States that elect to do mass-based trading under this

option the State must indicate in its plan that its emission budget trading program will be administered using an EPA-approved (or EPA-administered) emission and allowance tracking system.

(2) ~~The existing state program, requirement, or measure, and any related actions taken pursuant to such program, requirement, or measure, meet the applicable requirements pursuant to § 60.5740(a) and § 60.5780.~~For States that elect to use a rate-based trading program which allows the affected EGUs to use ERCs from other State rate-based trading programs, the plan must require affected EGUs within their State to comply with emission standards equal to the sub-category CO2 emission performance rates in Table 1 of this subpart.

~~§ 60.5755 What are the timing~~
§ 60.5760 What are the timing requirements for submitting my ~~state~~ plan?

(a) You must submit ~~your state~~a final plan with the information ~~in § 60.5740 by June 30, 2016 unless you are submitting a request for extension according to paragraphs (b) or (c) of this section.~~required under § 60.5745 by September 6, 2016, unless you are submitting an initial submittal, allowed under § 60.5765, in lieu of a final State plan submittal, according to paragraph (b) of this section.

(b) For ~~a state~~States seeking a ~~one~~two year extension for a ~~complete~~final plan submittal, you must include the information in § ~~60.5760~~60.5765(a) in ~~a~~an initial submittal by ~~June 30~~September 6, 2016, to receive an extension to submit your ~~complete state~~final State plan submittal by ~~June 30~~September 6, ~~2017~~2018.

(c) ~~For states in a multi-state plan seeking a two year extension for a complete plan submittal you must include the information in § 60.5760(a) in a submittal by June 30, 2016 to receive an extension to submit your complete multi-state plan by June 30, 2018.~~You must submit all information required under paragraphs (a) and (b) of this section according to the electronic reporting requirements in § 60.5875.

§ ~~60.5760~~60.5765 What must I include in an initial submittal ~~in lieu of a complete state~~if requesting an extension for a final plan submittal?

(a) You must ~~include~~sufficiently demonstrate that your State is able to undertake steps and processes necessary to timely submit a final plan by the extended date of September 6, 2018, by addressing the following required ~~elements~~components in an initial submittal ~~in lieu of a complete state~~by September 6, 2016, if requesting an extension for a final plan submittal:

(1) ~~A description of the~~An identification of final plan approach ~~and~~or approaches under consideration and a description of progress made to date ~~in developing each of~~on the final plan ~~elements in § 60.5740~~components;

~~(2) An initial projection of the level of emission performance that will be achieved under the complete plan;~~

~~(3) A commitment by the state to maintain existing state programs and measures that limit or avoid CO2 emissions from affected entities (e.g., renewable energy standards, unit-specific limits on operation or fuel utilization), which must at a minimum apply during the interim period prior to state submission and EPA approval of a complete plan, and must continue to apply in lieu of a complete plan if one is ultimately not submitted and approved;~~

(~~4~~2) ~~Justification of why~~An appropriate explanation of why the State requires additional time ~~is needed~~ to submit a ~~complete~~final plan by September 6, 2018; and

~~(5) A comprehensive roadmap for completing the plan, including process, analytical methods and schedule (including milestones) specifying when all necessary plan components will be complete (e.g., projection of emission performance; implementing legislation, regulations and agreements; necessary approvals);~~

~~(6) Identification of existing and future programs, requirements, and measures the state intends to include in the plan;~~

~~(7) If a multi-state plan is being developed, an executed agreement(s) with other states (e.g., MOU) participating in the development of the multistate plan; and~~

(~~8~~3) A ~~commitment to submit a complete plan by June 30, 2017, for a single-state plan, or June 30, 2018, for a multi-state plan, and actions the state will take to show progress in addressing incomplete plan components prior to submittal of the complete~~demonstration or description of the opportunity for public comment on the initial submittal and meaningful engagement with stakeholders, including vulnerable communities, during the time in preparation of the initial submittal and the plans for engagement during development of the final plan.

~~(9) A description of all steps the state has already taken in furtherance of actions needed to finalize a complete plan.~~

~~(10) Evidence of an opportunity for public comment and a response to any significant comments received on issues relating to the approvability of the initial plan.~~

(b) You must submit ~~either a complete state plan or~~ an initial submittal ~~by June 30, 2016. Where~~allowed in paragraph (a) of this section, information required under paragraph (c) of this section (only if a State elects to submit an initial submittal ~~is submitted in lieu of a complete state plan the due date of a complete state plan will be June 30, 2017, for a single-state plan, or June 30, 2018, for a multistate plan~~to request an extension for a final plan submittal), and a final State plan submittal according to § 60.5870. If a State submits an initial submittal, an extension for a final State plan submittal is considered granted and a final State plan submittal is due according to § 60.5760(b) unless a ~~state~~State is notified within ~~60~~90 days of the EPA receiving the initial submittal ~~in paragraph (a) of this section~~ that the EPA finds the initial submittal does not meet the requirements listed in paragraph (a) of this section. If the EPA notifies the State that the initial submittal does not meet such requirements, the EPA will also notify the State that it has failed to submit the final plan required by September 6, 2016.

(c) If an extension for submission of a final plan has been granted, you must submit a progress report by September 6, 2017. The 2017 report must include the following:

~~§ 60.5765 What are the state rate-based CO_2 emissions performance goals?~~

~~(a) The annual average state rate-based CO2 emission performance goals for the interim performance periods of 2020 through 2029, and the final 2030 and thereafter period are respectively listed in Table 1 of this Subpart. The state rate-based CO2 emission performance goal may be converted to a mass-based emission performance goal according to § 60.5770.~~

~~(b)[Reserved]~~

~~§ 60.5770 What is the procedure for converting my state rate-based CO_2 emission performance goal to a mass-based CO_2 emissions performance goal?~~

~~(a) If the plan adopts a mass-based goal according to § 60.5740(a)(3), the plan must identify the mass-based goal, in tons of CO2 emitted by affected EGUs over the plan performance period, and include a description of the analytic process, tools, methods, and assumptions used to convert from the rate-based goal for the state identified in Table 1 of this Subpart to an equivalent mass-based goal. The conversion process must include following requirements:~~

(1) ~~The process, tools, methods, and assumptions used in the conversion of the rate-based goal must be included in your state plan according to § 60.5740(a)(11).~~ A summary of the status of each component of the final plan, including an update from the 2016 initial submittal and a list of which final plan components are not complete.

(2) ~~The material supporting the conversion of the rate-based goal, including results, data, and descriptions, must be include in a state plan according to § 60.5740(a)(11).~~A commitment to a plan approach (e.g., single or multi-State, rate-based or mass-based emission performance level, rate-based or mass-based emission standards), including draft or proposed legislation and/or regulations.

(3) An updated comprehensive roadmap with a schedule and milestones for completing the final plan, including any updates to community engagement undertaken and planned.

~~(3) The conversion must represent the tons of CO2 emissions that are projected to be emitted by affected EGUs, in the absence of emission standards contained in the plan, if the affected EGUs were to perform at an average lb CO2/MWh rate equal to the rate-based goal for the state identified in Table 1 of this Subpart.~~

~~(b) [Reserved]~~

§ ~~60.5775~~60.5770 What schedules, performance periods, and compliance periods must I include in my ~~state~~ plan?

(a) The affected EGUs covered by your plan must meet the CO2 emission requirements required under § 60.5855 for the interim period, interim steps, and the final reporting periods according to paragraph (b) of this section. You must also include in your plan compliance periods for each affected EGU regulated under the plan according to paragraphs (c) and (d) of this section.

(b) Your plan must require your affected EGUs to achieve each CO2 emission performance rate or CO2 emission goal, as applicable, required under § 60.5855 over the periods according to paragraphs (b)(1) through (3) of this section.

(1) The interim period.

(2) Each interim step.

(3) Each final reporting period.

(~~a~~c) ~~Your state~~The emission standards for affected EGUs regulated under the plan must include ~~a schedule of~~the following compliance ~~for each~~periods:

(1) For the interim period, affected EGUs must have emission standards that have compliance periods that are no longer than each interim step and are imposed for the entirety of the interim step either alone or in combination.

(2) For the final period, affected EGUs must have emission standards that have compliance periods that are no longer than each final reporting period and are imposed for the entirety of the final reporting period either alone or in combination.

(3) Compliance periods for each interim step and each final reporting period may take forms shorter than specified in this regulation, provided the schedules of compliance collectively end on the same schedule as each interim step and final reporting period.

(d) If your plan relies upon State measures in lieu of or in addition to emission standards for affected EGUs regulated under the plan, then the performance periods must be identical to the compliance periods for affected EGUs listed in paragraphs (c)(1) through (3) of this section.

~~affected entity regulated under the plan.~~

~~(b) Your state plan must include compliance periods, as defined in section § 60.5820, for each affected entity regulated under the plan.~~

~~(c) For the interim performance period of 2020–2029 your state must meet the requirements in paragraphs (c)(1) and (2) of this section.~~

~~(1) Your state plan must include increments of emissions performance (either rate based or mass based with respect to the interim level of performance set in the state plan) within the interim performance period for every 2-rolling calendar years starting January 1, 2020 and ending in 2028 (i.e. 2020–2021, 2021–2022, 2022–2023, etc.), unless other periods that ensure regular progress in the interim period are approved by the Administrator.~~

~~(2) At the end of 2029 your state must meet the interim emissions performance level specified in § 60.5740(a)(3) as averaged over the plan performance period 2020–2029.~~

~~(d) During the final performance period, 2030 and thereafter, your state must meet the final emission performance level specified in § 60.5740(a)(3) on a 3-calendar year rolling average starting January 1, 2030 (i.e., 2030–2032, 2031–2033, 2032–2034, etc.).~~

~~(e) You must include the provisions of your state plan which demonstrate progress and compliance with the requirements in this § 60.5775 and § 60.5740 in your state's annual report required in § 60.5815.~~

§ ~~60.5780~~60.5775 What emission standards ~~and enforcing measures~~ must I include in my plan?

(a) ~~Your state plan shall include emission~~Emission standard(s) ~~that are~~for affected EGUs included under your plan must be demonstrated to be quantifiable, verifiable, non-duplicative, permanent, and enforceable with respect to each affected ~~entity~~EGU. The plan ~~shall~~submittal must include the methods by which each emission standard meets each of the following requirements in paragraphs (b) through (f) of this section.

(b) An **affected EGU's** emission standard is quantifiable ~~with respect to an affected entity~~ if it can be reliably measured~~,~~ in a manner that can be replicated.

(c) An **affected EGU's** emission standard is verifiable ~~with respect to an affected entity~~ if adequate monitoring, recordkeeping and reporting requirements are in place to enable the ~~state~~State and the Administrator to independently evaluate, measure, and verify compliance with the emission standard.

(d) An **affected EGU's** emission standard is non-duplicative with respect to ~~an affected entity~~a State plan if it is not already incorporated as an emission standard in another ~~state~~State plan unless incorporated in ~~multi-state~~multi-State plan.

(e) An **affected EGU's** emission standard is permanent ~~with respect to an affected entity~~ if the emission standard must be met for each compliance period, ~~or~~ unless it is replaced by another emission standard in an approved plan revision, or the ~~state~~State demonstrates in an ~~approved~~approvable plan revision that the emission reductions from the emission standard are no longer necessary for the ~~state~~State to meet its ~~state~~State level of performance.

(f) An **affected EGU's** emission standard is enforceable if:~~enforceable against an affected entity if:~~ (1) A technically accurate limitation or requirement and the time period for the limitation or requirement ~~is~~are specified;

(2) Compliance requirements are clearly defined;

(3) The affected ~~entities~~EGUs responsible for compliance and liable for violations can be identified;

(4) Each compliance activity or measure is enforceable as a practical matter; and

(5) The Administrator ~~and~~, the ~~state~~State, and third parties maintain the ability to enforce against violations (including if an affected EGU does not meet its emission standard based on its emissions, its allowances if it is subject to a mass-based emission standard, or its ERCs if it is subject to a rate-based emission standard) and secure appropriate corrective actions, in the case of the Administrator pursuant to CAA sections 113(a) ~~through~~–(h) ~~of the Act~~, in the case of a State, pursuant to its plan, State law or CAA section 304, as applicable, and in the case of third parties, pursuant to CAA section 304.

§ 60.5780 What State measures may I rely upon in support of my plan?

You may rely upon State measures in support of your plan that are not emission standard(s) on affected EGUs, provided those State measures meet the requirements in paragraph (a) of this section.

(a) Each State measure is quantifiable, verifiable, non-duplicative, permanent, and enforceable with respect to each affected entity (e.g., entities other than affected EGUs with no federally enforceable obligations under a State plan), and your plan supporting materials include the methods by which each State measure meets each of the following requirements in paragraphs (a)(1) through (5) of this section.

(1) A State measure is quantifiable with respect to an affected entity if it can be reliably measured in a manner that can be replicated.

(2) A State measure is verifiable with respect to an affected entity if adequate monitoring, recordkeeping and reporting requirements are in place to enable the State to independently evaluate, measure, and verify compliance with the State measure.

(3) A State measure is non-duplicative with respect to an affected entity if it is not already incorporated as a State measure or an emission standard in another State plan or State plan supporting material unless incorporated in a multi-State plan.

(4) A State measure is permanent with respect to an affected entity if the State measure must be met for at least each compliance period, or unless either it is replaced by another State measure in an approved plan revision, or the State demonstrates in an approved plan revision that the emission reductions from the State measure are no longer necessary for the State's affected EGUs to meet their mass-based CO2 emission goal.

(5) A State measure is enforceable against an affected entity if:

(i) A technically accurate limitation or requirement and the time period for the limitation or requirement are specified;

(ii) Compliance requirements are clearly defined;

(iii) The affected entities responsible for compliance and liable for violations can be identified;

(iv) Each compliance activity or measure is enforceable as a practical matter; and

(v) The State maintains the ability to enforce violations and secure appropriate corrective actions.

(b) [Reserved]

§ 60.5785 What is the procedure for revising my ~~state~~ plan?

~~State plans can only be revised with approval by the Administrator. If one (or more) of the elements of the state plan set in § 60.5740 require revision with respect to reaching the emission performance goal set in § 60.5765 a request may be submitted to the Administrator indicating the proposed corrections to the state plan to ensure the emission performance goal is met.~~

(a) EPA-approved plans can be revised only with approval by the Administrator. The Administrator will approve a plan revision if it is satisfactory with respect to the applicable requirements of this subpart and any applicable requirements of subpart B of this part, including the requirement in § 60.5745(a)(3) to demonstrate achievement of the CO_2 emission performance rates or CO_2 emission goals in § 60.5855. If one (or more) of the elements of the plan set in § 60.5740 require revision with respect to achieving the CO_2 emission performance rates or CO_2 emission goals in § 60.5855, a request must be submitted to the Administrator indicating the proposed revisions to the plan to ensure the CO_2 emission performance rates or CO_2 emission goals are met. In addition, the following provisions in paragraphs (b) through (d) of this section may apply.

(b) You may submit revisions to a plan to adjust CO_2 emission goals according to § 60.5855(d).

(c) If your State is required to submit a notification according to § 60.5870(d) indicating a triggering of corrective measures as described in § 60.5740(a)(2)(i) and your plan does not already include corrective measures to be implemented if triggered, you must revise your State plan to include corrective measures to be implemented. The corrective measures must ensure achievement of the CO_2 emission performance rates or State CO_2 emission goal. Additionally, the corrective measures must achieve additional CO_2 emission reductions to offset any CO_2 emission performance shortfall relative to the overall interim period or final period CO2 emission performance rate or State CO2 emission goal. The State plan revision submission must explain how the corrective measures both make up for the shortfall and address the State plan deficiency that caused the shortfall. The State must submit the revised plan and explanation to the EPA within 24 months after submitting the State report required in § 60.5870(a) indicating the CO2 emission performance deficiency in lieu of the requirements of § 60.28(a). The State must implement corrective measures within 6 months of the EPA's approval of a plan revision adding them. The shortfall must be made up as expeditiously as practicable.

(d) If your plan relies upon State measures, your backstop is triggered under § 60.5740(a)(3)(i), and your State measures plan backstop does not include a mechanism to make up the shortfall, you must revise your backstop emission standards to make up the shortfall. The shortfall must be made up as expeditiously as practicable.

(e) Reliability Safety Valve:

(1) In order to trigger a reliability safety valve, you must notify the EPA within 48 hours of an unforeseen, emergency situation that threatens reliability, such that your State will need a short-term modification of emission standards under a State plan for a specified affected EGU or EGUs. The EPA will consider the notification in § 60.5870(g)(1) to be an approved short-term modification to the State plan without needing to go through the full State plan revision process if the State provides a second notification to the EPA within seven days of the first notification. The short-term modification under a reliability safety valve allows modification to emission standards under the State plan for an affected EGU or EGUs for an initial period of up to 90 days. During that period of time, the affected EGU or EGUs will need to comply with the modified emission standards identified in the initial notification required under § 60.5870(g)(1) or amended in the second notification required under § 60.5870(g)(2). For the duration of the up to 90-day short-term modification, the CO2 emissions of the affected EGU or EGUs that exceed their obligations under the originally approved State plan will not be counted against the State's CO2 emission performance rate or CO2 emission goal. The EPA reserves the right to review any such

notification required under § 60.5870(g), and, in the event that the EPA finds such notification is improper, the EPA may disallow the short-term modification and affected EGUs must continue to operate under the approved State plan emission standards. As described more fully in § 60.5870(g)(3), at least seven days before the end of the initial 90-day reliability safety valve period, the State must notify the appropriate EPA regional office whether the reliability concern has been addressed and the affected EGU or EGUs can resume meeting the original emission standards established in the State plan prior to the short-term modification or whether a serious, ongoing reliability issue necessitates the affected EGU or EGUs emitting beyond the amount allowed under the State plan.

(2) Plan revisions submitted pursuant to § 60.5870(g)(3) must meet the requirements for State plan revisions under § 60.5785(a).

§ 60.5790 What must I do to meet my plan obligations?

(a) To meet your plan obligations, you must demonstrate that your affected EGUs are complying with their emission standards as specified in § 60.5740, and you must demonstrate that the emission standards on affected EGUs, alone or in conjunction with any State measures, are resulting in achievement of the CO_2 emission performance rates or statewide CO_2 emission goals by affected EGUs using the procedures in paragraphs (b) through (d) of this section. If your plan requires the use of allowances for your affected EGUs to comply with their mass-based emission standards, you must follow the requirements under paragraph (b) of this section and § 60.5830. If your plan requires the use of ERCs for your affected EGUs to comply with their rate-based emission standards, you must follow the requirements under paragraphs (c) and (d) of this section and §§ 60.5795 through 60.5805.

(b) If you submit a plan that sets a mass-based emission trading program for your affected EGUs, the State plan must include emission standards and requirements that specify the allowance system, related compliance requirements and mechanisms, and the emission budget as appropriate. These requirements must include those listed in paragraphs (b)(1) through (5) of this section.

(1) CO_2 emission monitoring, reporting, and recordkeeping requirements for affected EGUs.

(2) Requirements for State allocation of allowances consistent with § 60.5815.

(3) Requirements for tracking of allowances, from issuance through submission for compliance, consistent with § 60.5820.

(4) The process for affected EGUs to demonstrate compliance (allowance "true-up" with reported CO_2 emissions) consistent with § 60.5825.

(5) Requirements that address potential increased CO_2 emissions from new sources, beyond the emissions expected from new sources if affected EGUs were given emission standards in the form of the subcategory-specific CO_2 emission performance rates. You may meet this requirement by requiring one of the options under paragraphs (b)(5)(i) through (iii) of this section.

(i) You may include, as part of your plan's supporting documentation, requirements enforceable as a matter of State law regulating CO_2 emissions from EGUs covered by subpart TTTT of this part under the mass-based CO_2 goal plus new source CO_2 emission complement applicable to your State in Table 4 of this subpart. If you choose this option, the term "mass-based CO_2 goal plus new source CO_2 emission complement" shall apply rather than "CO_2 mass-based goal" and the term "CO_2 emission goal" shall include "mass-based CO_2 goal plus new source CO_2 emission complement" in these emission guidelines.

(ii) You may include requirements in your State plan for emission budget allowance allocation methods that align incentives to generate to affected EGUs or EGUs covered by subpart TTTT of this part that result in the affected EGUs meeting the mass-based CO_2 emission goal;

(iii) You may submit for the EPA's approval, an equivalent method which requires affected EGUs to meet the mass-based CO_2 emission goal. The EPA will evaluate the approvability of such an alternative method on a case by case basis.

(c) If you submit a plan that sets rate-based emission standards on your affected EGUs, to meet the requirements of § 60.5775, you must follow the requirements in paragraphs (c)(1) through (4) of this section.

(1) You must require the owner or operator of each affected EGU covered by your plan to calculate an adjusted CO2 emission rate to demonstrate compliance with its emission standard by factoring stack emissions and any ERCs into the following equation:

(Add)

$$CO_2\,emission\,rate = \frac{\sum M_{CO2}}{\sum MWh_{op} + \sum MWh_{ERC}}$$

Where:

CO2 emission rate = An affected EGU's adjusted CO2 emission rate that will be used to determine compliance with the applicable CO2 emission standard.

MCO2 = Measured CO2 mass in units of pounds (lbs) summed over the compliance period for an affected EGU.

MWhop = Total net energy output over the compliance period for an affected EGU in units of MWh.

MWhERC = ERC replacement generation for an affected EGU in units of MWh (ERCs are denominated in whole integers as specified in paragraph (d) of this section).

(2) Your plan must specify that an ERC qualifies for the compliance demonstration specified in paragraph (c)(1) of this section if the ERC meets the requirements of paragraphs (c)(2)(i) through (iv) of this section.

(i) An ERC must have a unique serial number.

(ii) An ERC must represent one MWh of actual energy generated or saved with zero associated CO2 emissions.

(iii) An ERC must only be issued to an eligible resource that meets the requirements of § 60.5800 or to an affected EGU that meets the requirements of § 60.5795 and must only be

issued by a State or its State agent through an EPA-approved ERC tracking system that meets the requirements of § 60.5810, or by the EPA through an EPA-administered tracking system.

(iv) An ERC must be surrendered and retired only once for purpose of compliance with this regulation through an EPA-approved ERC tracking system that meets the requirements of § 60.5810, or by the EPA through an EPA-administered tracking system.

(3) Your plan must specify that an ERC does not qualify for the compliance demonstration specified in paragraph (c)(1) of this section if it does not meet the requirements of paragraph (c)(2) of this section or if any State has used that same ERC for purposes of demonstrating achievement of a CO2 emission performance rate or CO2 emission goal. The plan must additionally include provisions that address requirements for revocation or adjustment that apply if an ERC issued by the State is subsequently found to have been improperly issued.

(4) Your plan must include provisions either allowing for or restricting banking of ERCs between compliance periods for affected EGUs, and provisions not allowing any borrowing of any ERCs from future compliance periods by affected EGUs or eligible resources.

Emission Rate Credit Requirements

§ 60.5795 What affected EGUs qualify for generation of ERCs?

(a) For issuance of ERCs to the affected EGUs that generate them, the plan must specify the accounting method and process for ERC issuance. For plans that require that affected EGUs meet a rate-based CO2 emission goal, where all affected EGUs have identical emission standards, you must specify the accounting method listed in paragraph (a)(1) of this section for generating ERCs. For plans that require affected EGUs to meet the CO2 emission performance rates or CO2 emission goals where affected EGUs have emission standards that are not equal for all affected EGUs, you must specify the accounting methods listed in paragraphs (a)(1) and (2) of this section for generating ERCs.

(1) You must include the calculation method for determining the number of ERCs, denominated in MWh, that may be generated by and issued to an affected EGU that is in

compliance with its emission standard, based on the difference between its emission standard and its reported CO2 emission rate for the compliance period; and

(2) You must include the calculation method for determining the number of ERCs, denominated in MWh, that may be issued to affected EGUs that meet the definition of a stationary combustion turbine based on the displaced emissions from affected EGUs not meeting the definition of a stationary combustion turbine, resulting from the difference between its annualized net energy output in MWh for the calendar year(s) in the compliance period and its net energy output in MWh for the 2012 calendar year (January 1, 2012, through December 31, 2012).

(b) Any ERCs generated through the method described as required by paragraph (a)(2) of this section must not be used by any affected EGUs other than steam generating units or IGCCs to demonstrate compliance as prescribed under § 60.5790(c)(1).

(c) Any states in a multi-State plan that requires the use of ERCs for affected EGUs to comply with their emission standards must have functionally equivalent requirements pursuant to paragraphs (a)(1) and (2) of this section for generating ERCs.

§ 60.5800 What other resources qualify for issuance of ERCs?

(a) ERCs may only be issued for generation or savings produced on or after January 1, 2022, to a resource that qualifies as an eligible resource because it meets each of the requirements in paragraphs (a)(1) through (4) of this section.

(1) Resources qualifying for eligibility only include resources that increased installed electrical generation nameplate capacity, or implemented new electrical savings measures, on or after January 1, 2013. If a resource had a nameplate capacity uprate, ERCs may be issued only for the difference in generation between its uprated nameplate capacity and its nameplate capacity prior to the uprate. ERCs must not be issued for generation for an uprate that followed a derate that occurred on or after January 1, 2013. A resource that is relicensed or receives a license extension is considered existing capacity and is not an eligible resource, unless it receives a capacity uprate as a result of the relicensing process that is reflected in its relicensed permit. In such a case, only

the difference in nameplate capacity between its relicensed permit and its prior permit is eligible to be issued ERCs.

(2) The resource must be connected to, and deliver energy to or save electricity on, the electric grid in the contiguous United States.

(3) The resource must be located in either:

(i) A State whose affected EGUs are subject to rate-based emission standards pursuant to this regulation; or

(ii) A State with a mass-based CO2 emission goal, and the resource can demonstrate (e.g., through a power purchase agreement or contract for delivery) that the electricity generated is delivered with the intention to meet load in a State with affected EGUs which are subject to rate-based emission standards pursuant to this regulation, and was treated as a generation resource used to serve regional load that included the State whose affected EGUs are subject to rate-based emission standards. Notwithstanding any other provision of paragraph (a)(4) of this section, the only type of eligible resource in the State with mass-based emission standards is renewable generating technologies listed in (a)(4)(i) of this section.

(4) The resource falls into one of the following categories of resources:

(i) Renewable electric generating technologies using one of the following renewable energy resources: Wind, solar, geothermal, hydro, wave, tidal;

(ii) Qualified biomass;

(iii) Waste-to-energy (biogenic portion only);

(iv) Nuclear power;

(v) A non-affected combined heat and power (CHP) unit, including waste heat power;

(vi) A demand-side EE or demand-side management measure that saves electricity and is calculated on the basis of quantified ex post savings, not “projected” or “claimed” savings; or

(vii) A category identified in a State plan and approved by the EPA to generate ERCs.

(b) Any resource that does not meet the requirements of this subpart or an approved State plan cannot be issued ERCs for use by an affected EGU with its compliance demonstration required under § 60.5790(c).

(c) ERCs may not be issued to or for any of the following:

(1) New, modified, or reconstructed EGUs that are subject to subpart TTTT of this part, except CHP units that meet the requirements of a CHP unit under paragraph (a);

(2) EGUs that do not meet the applicability requirements of §§ 60.5845 and 60.5850, except CHP units that meet the requirements of a CHP unit under paragraph (a);

(3) Measures that reduce CO2 emissions outside the electric power sector, including, for example, GHG offset projects representing emission reductions that occur in the forestry and agriculture sectors, direct air capture, and crediting of CO2 emission reductions that occur in the transportation sector as a result of vehicle electrification; and

(4) Any measure not approved by the EPA for issuance of ERCs in connection with a specific State plan.

(d) You must include the appropriate requirements in paragraphs (d)(1) through (3) of this section for an applicable eligible resource in your plan.

(1) If qualified biomass is an eligible resource, the plan must include a description of why the proposed feedstocks or feedstock categories should qualify as an approach for controlling increases of CO2 levels in the atmosphere as well as the proposed valuation of biogenic CO2 emissions. In addition, for sustainably-derived agricultural and forest biomass feedstocks, the state plan must adequately demonstrate that such feedstocks appropriately control increases of CO2 levels in the atmosphere and methods for adequately monitoring and verifying these feedstock sources and related sustainability practices. For all qualified biomass feedstocks, plans must specify how biogenic CO2 emissions will be monitored and reported, and identify specific EM&V, tracking and auditing approaches.

(2) If waste-to-energy is an eligible resource, the plan must assess both the capacity to strengthen existing or implement new waste reduction, reuse, recycling and composting programs, and measures to minimize any potential negative impacts of waste-to-energy operations on such programs. Additionally the plan must include a method for determining the proportion of total MWh generation from a waste-to-energy facility that is eligible for use in adjusting a CO2 emission rate (*i.e.*, that which is generated from biogenic materials).

(3) If carbon capture and utilization (CCU) is an eligible resource in a plan, the plan must include analysis supporting how the proposed qualifying CCU technology results in CO2 emission mitigation from affected EGUs and provide monitoring, reporting, and verification requirements to demonstrate the reductions.

(e) States and areas of Indian country that do not have any affected EGUs, and other countries, may provide ERCs to adjust CO2 emissions provided they are connected to the contiguous U.S. grid and meet the other requirements for eligibility and eligible resources and the issuance of ERCs included in these emission guidelines, except that such States and other countries may not provide ERCs from resources described in § 60.5800(a)(4)(vi).

§ 60.5805 What is the process for the issuance of ERCs?

If your plan uses ERCs your plan must include the process and requirements for issuance of ERCs to affected EGUs and eligible resources set forth in paragraphs (a) through (f) of this section.

(a) *Eligibility application.* Your plan must require that, to receive ERCs, the owner or operator must submit an eligibility application to you that demonstrates that the requirements of your State plan as approved by the EPA as meeting § 60.5795 (for an affected EGU) or § 60.5800 (for an eligible resource) are met, and, in the case of an eligible resource, includes at a minimum:

(1) Documentation that the eligibility application has only been submitted to you, or pursuant to an EPA-approved multi-State collaborative approach;

(2) An EM&V plan that meets the requirements of the State plan as approved by the EPA as meeting § 60.5830; and

(3) A verification report from an independent verifier that verifies the eligibility of the eligible resource to be issued an ERC and that the EM&V plan meets the requirements of the State plan as approved by the EPA of meeting § 60.5805.

(b) *Registration.* Your plan must require that any affected EGU or eligible resource register with an ERC tracking system that meets the requirements of § 60.5810 prior to the issuance of ERCs, and your plan must specify that you will only register an affected EGU or eligible resource after you approve its eligibility application and determine that the requirements of paragraph (a) of this section are met.

(c) *M&V reports.* For an eligible resource registered pursuant to paragraph (b) of this section, your plan must require that, prior to issuance of ERCs by you, the owner or operator must submit the following:

(1) An M&V report that meets the requirements of your State plan as approved by the EPA as meeting § 60.5835; and

(2) A verification report from an independent verifier that verifies that the requirements for the M&V report are met.

(e) *Issuance of ERCs.* Your plan must specify your procedure for issuance of ERCs based on your review of an M&V report and verification report, and must require that ERCs be issued only on the basis of energy actually generated or saved, and that only one ERC is issued for each verified MWh.

(f) *Tracking system.* Your plan must require that ERCs may only be issued through an ERC tracking system approved as part of the State plan.

(g) *Error adjustment.* Your plan must include a mechanism to adjust the number of ERCs issued if any are issued based on error (clerical, formula input error, etc.).

(h) *Qualification status of an eligible resource.* Your plan must include a mechanism to temporarily or permanently revoke the qualification status of an eligible resource, such that it can no longer be issued

ERCs for at least the duration that it does not meet the requirements for being issued ERCs in your State plan.

(i) *Qualification status of an independent verifier*—(1) *Eligibility.* To be an independent verifier, a person must be approved by the State as:

(A) An independent verifier, as defined by this regulation; and

(B) Eligible to verify eligibility applications, EM&V plans, and/or M&V reports per the requirements of the approved State plan as meeting §§ 60.5830 and 60.5835 respectively.

(2) *Revocation of qualification.* Your plan must include a mechanism to temporarily or permanently revoke the qualification status of an independent verifier, such that it can no longer verify eligibility applications, EM&V plans or M&V reports for at least the duration of the period it does not meet the requirements of your State plan.

§ 60.5810 What applicable requirements are there for an ERC tracking system?

(a) Your plan must include provisions for an ERC tracking system, if applicable, that meets the following requirements:

(1) It electronically records the issuance of ERCs, transfers of ERCs among accounts, surrender of ERCs by affected EGUs as part of a compliance demonstration, and retirement or cancellation of ERCs; and

(2) It documents and provides electronic, internet-based public access to all information that supports the eligibility of eligible resources and issuance of ERCs and functionality to generate reports based on such information, which must include, for each ERC, an eligibility application, EM&V plan, M&V reports, and independent verifier verification reports.

(b) If approved in a State plan, an ERC tracking system may provide for transfers of ERCs to or from another ERC tracking system approved in a State plan, or provide for transfers of ERCs to or from an EPA-administered ERC tracking system used to administer a Federal plan.

Mass Allocation Requirements

§ 60.5815 What are the requirements for State allocation of allowances in a mass-based program?

(a) For a mass-based trading program, a State plan must include requirements for CO_2 allowance allocations according to paragraphs (b) through (f) of this section.

(b) Provisions for allocation of allowances for each compliance period prior to the beginning of the compliance period.

(c) Provisions for allocation of set-aside allowance, if applicable, must be established to ensure that the eligible resources must meet the same requirements for the ERC eligible resource requirements of § 60.5800, and the State must include eligibility application and verification provisions equivalent to those for ERCs in § 60.5805 and EM&V plan and M&V report provisions that meet the requirements of § 60.5830 and § 60.5835.

(d) Provisions for adjusting allocations if the affected EGUs or eligible resources are incorrectly allocated CO_2 allowances.

(e) Provisions allowing for or restricting banking of allowances between compliance periods for affected EGUs.

(f) Provisions not allowing any borrowing of allowances from future compliance periods by affected EGUs.

§ 60.5820 What are my allowance tracking requirements?

(a) Your plan must include provisions for an allowance tracking system, if applicable, that meets the following requirements:

(1) It electronically records the issuance of allowances, transfers of allowances among accounts, surrender of allowances by affected EGUs as part of a compliance demonstration, and retirement of allowances; and

(2) It documents and provides electronic, internet-based public access to all information that supports the eligibility of eligible resources and issuance of set aside allowances, if applicable, and functionality to generate reports based on such information, which must include, for each

set aside allowance, an eligibility application, EM&V plan, M&V reports, and independent verifier verification reports.

(b) If approved in a State plan, an allowance tracking system may provide for transfers of allowances to or from another allowance tracking system approved in a State plan, or provide for transfers of allowances to or from an EPA-administered allowance tracking system used to administer a Federal plan.

§ 60.5825 What is the process for affected EGUs to demonstrate compliance in a mass-based program?

(a) A plan must require an affected EGU's owners or operators to demonstrate compliance with emission standards in a mass based program by holding an amount of allowances not less than the tons of total CO2 emissions for such compliance period from the affected EGUs in the account for the affected EGU's emissions in the allowance tracking system required under § 60.5820 during the applicable compliance period.

(b) In a mass-based trading program a plan may allow multiple affected EGUs co-located at the same facility to demonstrate that they are meeting the applicable emission standards on a facility-wide basis by the owner or operator holding enough allowances to cover the CO2 emissions of all the affected EGUs at the facility.

(1) If there are not enough allowances to cover the facility's affected EGUs' CO2 emissions then there must be provisions for determining the compliance status of each affected EGU located at that facility.

(2) [Reserved]

Evaluation Measurement and Verification Plans and Monitoring and Verification Reports

§ 60.5830 What are the requirements for EM&V plans for eligible resources?

(a) If your plan requires your affected EGUs to meet their emission standards in accordance with § 60.5790, your plan must include requirements that any EM&V plan that is submitted in accordance with the requirements of § 60.5805, in support of the issuance of an ERC or set-aside allowance that can be used in accordance with § 60.5790, must meet the EM&V criteria approved as part of your State plan.

(b) Your plan must require each EM&V plan to include identification of the eligible resource.

(c) Your plan must require that an EM&V plan must contain specific criteria, as applicable to the specific eligible resource.

(1) For RE resources, your plan must include requirements discussing how the generation data will be physically measured on a continuous basis using, for example, a revenue-quality meter.

(2) For demand-side EE, your plan must require that each EM&V plan quantify and verify electricity savings on a retrospective (ex-post) basis using industry best-practice EM&V protocols and methods that yield accurate and reliable measurements of electricity savings. Your plan must also require each EM&V plan to include an assessment of the independent factors that influence the electricity savings, the expected life of the savings (in years), and a baseline that represents what would have happened in the absence of the demand-side EE activity. Additionally, your plan must require that each EM&V plan include a demonstration of how the industry best-practices protocol and methods were applied to the specific activity, project, measure, or program covered in the EM&V plan, and include an explanation of why these protocols or methods were selected. EM&V plans must require eligible resources to demonstrate how all such best-practice approaches will be applied for the purposes of quantifying and verifying MWh results. Subsequent reporting of demand-side EE savings values must demonstrate and explain how the EM&V plan was followed.

§ 60.5835 What are the requirements for M&V reports for eligible resources?

(a) If your plan requires your affected EGUs to meet their emission standards in accordance with § 60.5790, your plan must include requirements that any M&V report that is submitted in accordance with the requirements of § 60.5805, in support of the issuance of an ERC or set-aside allocation that can be used in accordance with § 60.5790, must meet the requirements of this section.

(b) Your plan must require that each M&V report include the following:

(1) For the first M&V report submitted, documentation that the energy-generating resources, energy-saving measures, or practices were installed or implemented consistent with the description in the approved eligibility application required in § 60.5805(a).

(2) Each M&V report submitted must include the following:

(i) Identification of the time period covered by the M&V report;

(ii) A description of how relevant quantification methods, protocols, guidelines, and guidance specified in the EM&V plan were applied during the reporting period to generate the quantified MWh of generation or MWh of energy savings;

(iii) Documentation (including data) of the energy generation and/or energy savings from any activity, project, measure, resource, or program addressed in the EM&V plan, quantified and verified in MWh for the period covered by the M&V report, in accordance with its EM&V plan, and based on ex-post energy generation or savings; and

(iv) Documentation of any change in the energy generation or savings capability of the eligible resource from the description of the resource in the approved eligibility application during the period covered by the M&V report and the date on which the change occurred, and/or demonstration that the eligible resource continued to meet the requirements of § 60.5800.

Applicability of ~~State~~ Plans to Affected EGUs

§ ~~60.5790~~60.5840 Does this subpart directly affect EGU owners ~~and~~or operators in my ~~state~~State?

(a) This subpart does not directly affect EGU owners ~~and~~or operators in your ~~state~~State. However, affected EGU owners ~~and~~or operators must comply with the ~~state~~ plan that a ~~state develops~~State or States develop to implement the emission guidelines contained in this subpart.

(b) If a ~~state~~State does not submit ~~an approvable~~a final plan ~~or initial submittal~~ to implement and enforce the emission guidelines contained in this subpart ~~by June 30, 2016,~~, or an initial submittal for which an extension to submit a final plan can be granted, by September 6, 2016, or the EPA disapproves a final plan, the EPA will implement and enforce a Federal plan, as provided in §

~~60.5740, to ensure that~~60.5720, applicable to each affected EGU within the ~~state~~State that commenced construction on or before January 8, 2014 ~~reaches compliance with all the provisions of this subpart~~.

§ ~~60.5795~~60.5845 What affected EGUs must I address in my ~~state~~State plan?

(a) The EGUs that must be addressed by your ~~state~~ plan are any affected steam generating unit, IGCC, or stationary combustion turbine that ~~commences~~commenced construction on or before January 8, 2014.

(b) An affected EGU is a steam generating unit, ~~integrated gasification combined cycle (~~IGCC~~)~~, or stationary combustion turbine that meets the relevant applicability conditions specified in paragraph (b)(1) ~~or~~through (~~2~~3) of this section, as applicable, except as provided in § 60.5850.

(1) ~~A steam generating unit or IGCC that has a base load rating greater than~~Serves a generator or generators connected to a utility power distribution system with a nameplate capacity greater than 25 MW-net (*i.e.*, capable of selling greater than 25 MW of electricity); ~~73 MW~~

(2) Has a base load rating (*i.e.*, design heat input capacity) greater than 260 GJ/ hr (250 MMBtu/~~h~~hr) heat input of fossil fuel (either alone or in combination with any other fuel); and ~~was constructed for the purpose of supplying~~

(3) Stationary combustion turbines that meet the definition of either a combined cycle or combined heat and power combustion turbine.

§ 60.5850 What EGUs are excluded from being affected EGUs?

EGUs that are excluded from being affected EGUs are:

(a) EGUs that are subject to subpart TTTT of this part as a result of commencing construction after the subpart TTTT applicability date;

(b) Steam generating units and IGCCs that are, and always have been, subject to a federally enforceable permit limiting annual net-electric sales to one-third or ~~more~~less of its potential electric output ~~and more than~~, or 219,000 MWh ~~net-electric output to a utility distribution system on an annual basis.~~or less;

(c) Non-fossil units (*i.e.*, units that are capable of combusting 50 percent or more non-fossil fuel) that have always historically limited the use of fossil fuels to 10 percent or less of the annual capacity factor or are subject to a federally enforceable permit limiting fossil fuel use to 10 percent or less of the annual capacity factor;

(~~2~~d) ~~A stationary~~Stationary combustion ~~turbine that has a base load rating greater than 73 MW (250 MMBtu/h), was~~turbines not capable of combusting natural gas (*e.g.*, not connected to a natural gas pipeline); ~~constructed for the purpose of supplying, and supplies, one-third or more of its potential electric output and more than 219,000 MWh net-electrical output to a utility distribution system on a 3-year rolling average basis, combusts fossil fuel for more than 10.0 percent of the heat input during a 3-year rolling average basis and combusts over 90% natural gas on a heat input basis on a 3-year rolling average basis.~~

(e) EGUs that are combined heat and power units that have always historically limited, or are subject to a federally enforceable permit limiting, annual net-electric sales to a utility distribution system to no more than the greater of either 219,000 MWh or the product of the design efficiency and the potential electric output;

(f) EGUs that serve a generator along with other steam generating unit(s), IGCC(s), or stationary combustion turbine(s) where the effective generation capacity (determined based on a prorated output of the base load rating of each steam generating unit, IGCC, or stationary combustion turbine) is 25 MW or less;

(g) EGUs that are a municipal waste combustor unit that is subject to subpart Eb of this part; and

(h) EGUs that are a commercial or industrial solid waste incineration unit that is subject to subpart CCCC of this part.

§ ~~60.5800 What~~60.5855 What are the CO_2 emission performance rates for affected EGUs ~~are exempt from my state plan~~?

~~Affected EGUs that are exempt from your state plan include: those that are subject to subpart TTTT as a result of commencing construction or reconstruction after the subpart TTTT~~

~~applicability date; and those subject to subpart TTTT as a result of commencing modification or reconstruction prior becoming subject to an applicable state plan.~~

(a) You must require, in your plan, emission standards on affected EGUs to meet the CO2 emission performance rates listed in Table 1 of this subpart except as provided in paragraph (b) of this section. In addition, you must set CO2 emission performance rates for the interim steps, according to paragraph (a)(1) of this section, except as provided in paragraph (b) of this section.

(1) You must set CO2 emission performance rates for your affected EGUs to meet during the interim step periods on average and as applicable for the two subcategories of affected EGUs.

(2) [Reserved]

(b) You may elect to require your affected EGUs to meet emission standards that differ from the CO2 emission performance rates listed in Table 1 of this subpart, provided that you demonstrate that the affected EGUs in your State will collectively meet their CO2 emission performance rate by achieving statewide emission goals that are equivalent and no less stringent than the CO2 emission performance rates listed in Table 1, and provided that your equivalent statewide CO2 emission goals take one of the following forms:

(1) Average statewide rate-based CO2 emission goals listed in Table 2 of this subpart, except as provided in paragraphs (c) and (d); or

(2) Cumulative statewide mass-based CO2 emission goals listed in Table 3 of this subpart, except as provided in paragraphs (c) and (d) of this section.

(c) If your plan meets CO2 emission goals listed in paragraphs (b)(1) or (2) of this section you must develop your own interim step goals and final reporting period goal for your affected EGUs to meet either on average (in the case of rate-based goals) or cumulatively (in the case of mass-based goals). Additionally the following applies if you develop your own goals:

(1) The interim period and interim steps CO2 emission goals must be in the same form, either both rate (in units of pounds per net MWh) or both mass (in tons); and

(2) You must set interim step goals that will either on average or cumulatively meet the State's interim period goal, as applicable to a rate-based or mass-based CO2 emission goal.

(d) Your plan's interim period and final period CO2 emission goals required to be met pursuant to paragraph (b)(1) or (2) of this section, may be changed in the plan only according to situations listed in paragraphs (d)(1) through (3) of this section. If a situation requires a plan revision, you must follow the procedures in § 60.5785 to submit a plan revision.

(1) If your plan implements CO2 emission goals, you may submit a plan or plan revision, allowed in § 60.5785, to make corrections to them, subject to EPA's approval, as a result of changes in the inventory of affected EGUs; and

(2) If you elect to require your affected EGUs to meet emission standards to meet mass-based CO2 emission goals in your plan, you may elect to incorporate, as a matter of state law, the mass emissions from EGUs that are subject to subpart TTTT of this part that are considered new affected EGUs under subpart TTTT of this part.

(e) If your plan relies upon State measures in addition to or in lieu of emission standards, you must only use the mass-based goals allowed for in paragraph (b)(2) of this section to demonstrate that your affected EGUs are meeting the required emissions performance.

(f) Nothing in this subpart precludes an affected EGU from complying with its emission standard or you from meeting your obligations under the State plan.

§ ~~60.5805~~60.5860 What applicable monitoring, recordkeeping, and reporting requirements do I need to include in my ~~state~~ plan for affected EGUs?

(a) ~~A state~~Your plan must include monitoring for affected EGUs that is no less stringent ~~that~~than what is described in (a)(1) through (~~6~~8) of this section.

(1) ~~If~~The owner or operator of an affected EGU (or group of affected EGUs that share a monitored common stack) that is required to meet ~~a rate based~~rate-based or mass-based emission ~~standard they~~standards must prepare a monitoring plan in accordance with the applicable provisions in § 75.53(g) and (h) of this chapter, unless such a plan is already in place under another program that requires CO2 mass emissions to be monitored and reported according to part 75 of this chapter.

(2) For rate-based emission standards, each compliance period shall include only "valid operating hours" in the compliance period, i.e., full or partial unit (or stack) operating hours for which:

(i) "Valid data" (as defined in § 60.5880) are obtained for all of the parameters used to determine the hourly CO2 mass emissions (lbs). For the purposes of this subpart, substitute data recorded under part 75 of this chapter are not considered to be valid data; and

(ii) The corresponding hourly net energy output value is also valid data (Note: For operating hours with no useful output, zero is considered to be a valid value).

(~~2~~3) ~~An~~**For rate-based emission standards, the owner or operator of an** affected EGU must measure **and report** the hourly CO2 mass emissions **(lbs)** from each affected unit using the procedures in paragraphs (a)(~~2~~3)(i) through (~~v~~vi) of this section, except as **otherwise** provided in paragraph (a)(~~3~~4) of this section.

(i) ~~An~~**The owner or operator of an** affected EGU must install, certify, operate, maintain, and calibrate a CO2 continuous emissions monitoring system (CEMS) to directly measure and record CO2 concentrations in the affected EGU exhaust gases emitted to the atmosphere and an exhaust gas flow rate monitoring system according to § 75.10(a)(3)(i) of this chapter. ~~If an affected EGU measures~~**As an alternative to direct measurement of** CO2 concentration**, provided that the affected EGU does not use carbon separation (e.g., carbon capture and storage), the owner or operator of an affected EGU may use data from a certified oxygen (O2) monitor to calculate hourly average CO2 concentrations, in accordance with § 75.10(a)(3)(iii) of this chapter. However, when an O2 monitor is used this way, it only quantifies the combustion CO2; therefore, if the EGU is equipped with emission controls that produce non-combustion CO2 (e.g., from sorbent injection), this additional CO2 must be accounted for, in accordance with section 3 of appendix G to part 75 of this chapter. If CO2 concentration is measured** on a dry basis, ~~they~~**the owner or operator of the affected EGU** must also install, certify, operate, maintain, and calibrate a continuous moisture monitoring system, according to § 75.11(b) of this chapter. **Alternatively, the owner or operator of an affected EGU may either use an appropriate fuel-**

specific default moisture value from § 75.11(b) or submit a petition to the Administrator under § 75.66 of this chapter for a site-specific default moisture value.

(ii) For each "valid operating hour" (as defined in paragraph (a)(2) of this section), calculate the hourly CO2 mass emission rate (tons/hr), either from Equation F–11 in Appendix F to part 75 of this chapter (if CO2 concentration is measured on a wet basis), or by following the procedure in section 4.2 of Appendix F to part 75 of this chapter (if CO2 concentration is measured on a dry basis).

(iii) Next, multiply each hourly CO2 mass emission rate by the EGU or stack operating time in hours (as defined in § 72.2 of this chapter), to convert it to tons of $_{CO2}$. Multiply the result by 2,000 lbs/ton to convert it to lbs.

(iv) The hourly CO2 tons/hr values and EGU (or stack) operating times used to calculate CO2 mass emissions are required to be recorded under § 75.57(e) of this chapter and must be reported electronically under § 75.64(a)(6), if required by a plan. The owner or operator must use these data, or equivalent data, to calculate the hourly CO2 mass emissions.

(v) Sum all of the hourly CO2 mass emissions values from paragraph (a)(3)(ii) of this section over the entire compliance period.

(~~ii~~**vi**) For each **continuous** monitoring system ~~an affected EGU uses~~**used** to determine the CO2 mass emissions~~, they~~ **from an affected EGU, the monitoring system** must meet the applicable certification and quality assurance procedures in § 75.20 of this chapter and Appendices **A and** B ~~and D~~ to part 75 of this chapter.

~~**(iii) An affected EGU must use a laser device to measure the dimensions of each exhaust gas stack or duct at the flow monitor and the reference method sampling locations prior to the initial setup (characterization) of the flow monitor. For circular stacks, an affected EGU must measure the diameter at three or more distinct locations and average the results. For rectangular stacks or ducts, an affected EGU must measure each dimension (i.e., depth and width) at three or more**~~

~~distinct locations and average the results. If the flow rate monitor or reference method sampling site is relocated, an affected EGU must repeat these measurements at the new location.~~

~~(iv) An affected EGU must use only unadjusted exhaust gas volumetric flow rates to determine the hourly CO2 mass emissions from the affected facility; an affected EGU must not apply the bias adjustment factors described in section 7.6.5 of Appendix A to part 75 of this chapter to the exhaust gas flow rate data.~~

~~(v) If an affected EGU chooses to use Method 2 in Appendix A–1 to this part to perform the required relative accuracy test audits (RATAs) of the part 75 flow rate monitoring system, they must use a calibrated Type-S pitot tube or pitot tube assembly. An affected EGU must not use the default Type-S pitot tube coefficient.~~

(~~3~~4) ~~If~~The owner or operator of an affected EGU that exclusively combusts liquid fuel and/or gaseous fuel may, as an alternative to complying with paragraph (~~b~~a)(3) of this section, ~~they may~~ determine the hourly CO_2 mass emissions ~~by using Equation G–4 in Appendix G to part 75 of this chapter~~ according to ~~the requirements in~~ paragraphs (a)(~~3~~4)(i) ~~and (ii~~through (a)(4)(vi) of this section.

(i) ~~An affected EGU must implement~~Implement the applicable procedures in appendix D to part 75 of this chapter to determine hourly ~~unit~~EGU heat input rates (MMBtu/~~h~~hr), based on hourly measurements of fuel flow rate and periodic determinations of the gross calorific value (GCV) of each fuel combusted. The fuel flow meter(s) used to measure the hourly fuel flow rates must meet the applicable certification and quality-assurance requirements in sections 2.1.5 and 2.1.6 of appendix D to part 75 (except for qualifying commercial billing meters). The fuel GCV must be determined in accordance with section 2.2 or 2.3 of appendix D, as applicable.

(ii) For each measured hourly heat input rate, use Equation G–4 in Appendix G to part 75 of this chapter to calculate the hourly CO_2 mass emission rate (tons/hr).

(iii) For each "valid operating hour" (as defined in paragraph (a)(2) of this section), multiply the hourly tons/hr CO_2 mass emission rate from paragraph (a)(4)(ii) of this section by the EGU or stack operating time in hours (as defined in § 72.2 of this chapter), to convert it to tons of CO2. Then, multiply the result by 2,000 lbs/ton to convert it to lbs.

(iv) The hourly CO2 tons/hr values and EGU (or stack) operating times used to calculate CO2 mass emissions are required to be recorded under § 75.57(e) of this chapter and must be reported electronically under § 75.64(a)(6), if required by a plan. You must use these data, or equivalent data, to calculate the hourly CO2 mass emissions.

(v) Sum all of the hourly CO2 mass emissions values (lb) from paragraph (a)(4)(iii) of this section over the entire compliance period.

(~~ii) An~~vi) The owner or operator of an affected EGU may determine site-specific carbon-based F-factors (F,;) using Equation F–7b in section 3.3.6 of appendix F to part 75 of this chapter, and may use these F,; values in the emissions calculations instead of using the default ~~Fc~~F,; values in the Equation G–4 nomenclature.

(~~4~~5) ~~An~~For both rate-based and mass-based standards, the owner or operator of an affected EGU (or group of affected units that share a monitored common stack) must install, calibrate, maintain, and operate a sufficient number of watt meters to continuously measure and record on an hourly basis net electric output. Measurements must be performed using 0.2 accuracy class electricity metering instrumentation and calibration procedures as specified under ANSI Standards No. C12.20. Further, the owner or operator of an affected EGU that is a combined heat and power facility must install, calibrate, maintain and operate equipment to continuously measure and record on an hourly basis useful thermal output and, if applicable, mechanical output, which are used with net electric output to determine net energy output. The owner or operator must use the following procedures to calculate net energy output, as appropriate for the type of affected EGU(s).

~~(5) In accordance with § 60.13(g), if two or more affected EGUs that implement the continuous emissions monitoring provisions in paragraph (a)(2) of this section share a common exhaust gas stack and are subject to the same emissions standard, they may monitor the hourly CO2 mass emissions at the common stack in lieu of monitoring each EGU separately. If an affected EGU~~

~~chooses this option, the hourly net electric output for the common stack must be the sum of the hourly net electric output of the individual affected facility and you must express the operating time as "stack operating hours" (as defined in § 72.2 of this chapter).~~

(i) Determine $_{Pnet}$ the hourly net energy output in MWh. For rate-based standards, perform this calculation only for valid operating hours (as defined in paragraph (a)(2) of this section). For mass-based standards, perform this calculation for all unit (or stack) operating hours, i.e., full or partial hours in which any fuel is combusted.

(ii) If there is no net electrical output, but there is mechanical or useful thermal output, either for a particular valid operating hour (for rate-based applications), or for a particular operating hour (for mass-based applications), the owner or operator of the affected EGU must still determine the net energy output for that hour.

(iii) For rate-based applications, if there is no (*i.e.*, zero) gross electrical, mechanical, or useful thermal output for a particular valid operating hour, that hour must be used in the compliance determination. For hours or partial hours where the gross electric output is equal to or less than the auxiliary loads, net electric output shall be counted as zero for this calculation.

(iv) Calculate $_{Pnet}$ for your affected EGU (or group of affected EGUs that share a monitored common stack) using the following equation. All terms in the equation must be expressed in units of MWh. To convert each hourly net energy output value reported under part 75 of this chapter to MWh, multiply by the corresponding EGU or stack operating time.

Where:

Pnet = Net energy output of your affected EGU for each valid operating hour (as defined in 60.5860(a)(2)) in MWh.

(Pe)ST = Electric energy output plus mechanical energy output (if any) of steam turbines in MWh.

$$\frac{(Add)_{ST} + (Pe)_{CT} + (Pe)_{IE} - (Pe)_A}{TDF} + [(Pt)_{PS} + (Pt)_{HR} + (Pt)_{IE}]$$

$$(Pt)_{PS} = \frac{Q_m \times H}{CF}$$

(Pe)CT = Electric energy output plus mechanical energy output (if any) of stationary combustion turbine(s) in MWh.

(Pe)IE = Electric energy output plus mechanical energy output (if any) of your affected EGU's integrated equipment that provides electricity or mechanical energy to the affected EGU or auxiliary equipment in MWh.

(Pe)A = Electric energy used for any auxiliary loads in MWh.

(Pt)PS = Useful thermal output of steam (measured relative to SATP conditions, as applicable) that is used for applications that do not generate additional electricity, produce mechanical energy output, or enhance the performance of the affected EGU. This is calculated using the equation specified in paragraph (a)(5)(v) of this section in MWh.

(Pt)HR = Non-steam useful thermal output (measured relative to SATP conditions, as applicable) from heat recovery that is used for applications other than steam generation or performance enhancement of the affected EGU in MWh.

(Pt)IE = Useful thermal output (relative to SATP conditions, as applicable) from any integrated equipment is used for applications that do not generate additional steam, electricity, produce mechanical energy output, or enhance the performance of the affected EGU in MWh.

TDF = Electric Transmission and Distribution Factor of 0.95 for a combined heat and power affected EGU where at least on an annual basis 20.0 percent of the total gross or net energy output consists of electric or direct mechanical output and 20.0 percent of the total net energy output consist of useful thermal output on a 12-operating month rolling average basis, or 1.0 for all other affected EGUs.

(v) If applicable to your affected EGU (for example, for combined heat and power), you must calculate (Pt)PS using the following equation:

Where:

Q_m = Measured steam flow in kilograms (kg) (or pounds (lbs)) for the operating hour.

H = Enthalpy of the steam at measured temperature and pressure (relative to SATP conditions or the energy in the condensate return line, as applicable) in Joules per kilogram (J/kg) (or Btu/lb).

CF = Conversion factor of 3.6×10^9 J/MWh or 3.413×10^6 Btu/MWh.

(vi) For rate-based standards, sum all of the values of $_{Pnet}$ for the valid operating hours (as defined in paragraph (a)(2) of this section), over the entire compliance period. Then, divide the total CO2 mass emissions for the valid operating hours from paragraph (a)(3)(v) or (a)(4)(v) of this section, as applicable, by the sum of the $_{Pnet}$ values for the valid operating hours plus any ERC replacement generation (as shown in § 60.5790(c)), to determine the CO2 emissions rate (lb/net MWh) for the compliance period.

(vii) For mass-based standards, sum all of the values of $_{Pnet}$ for all operating hours, over the entire compliance period.

(6) In accordance with § 60.13(g), if two or more affected EGUs implementing the continuous emissions monitoring provisions in paragraph (a)(2) of this section share a common exhaust gas stack and are subject to the same emissions standard, the owner or operator may monitor the hourly CO2 mass emissions at the common stack in lieu of monitoring each EGU separately. If an owner or operator of an affected EGU chooses this option, the hourly net electric output for the common stack must be the sum of the hourly net electric output of the individual affected EGUs and the operating time must be expressed as “stack operating hours” (as defined in § 72.2 of this chapter).

(~~6~~7) In accordance with § 60.13(g), if the exhaust gases from an affected EGU ~~that implements~~implementing the continuous emissions monitoring provisions in paragraph (a)(2) of this section are emitted to the atmosphere through multiple stacks (or if the exhaust gases are routed to a common stack through multiple ducts and you elect to monitor in the ducts), ~~they must monitor~~ the hourly CO2 mass emissions and the "stack operating time" (as defined in § 72.2 of this chapter) at each stack or duct **must be monitored** separately. In this case, **the owner or operator of** an affected EGU must determine compliance with an applicable emissions standard by summing the CO2 mass emissions measured at the individual stacks or ducts and dividing by the net energy output for the affected EGU.

~~**(b) An affected EGU must maintain records for at least 10 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record.**~~

(8) Consistent with § 60.5775 or § 60.5780, if two or more affected EGUs serve a common electric generator, you must apportion the combined hourly net energy output to the individual affected EGUs according to the fraction of the total steam load contributed by each EGU. Alternatively, if the EGUs are identical, you may apportion the combined hourly net electrical load to the individual EGUs according to the fraction of the total heat input contributed by each EGU.

(b) For mass-based standards, the owner or operator of an affected EGU must determine the CO2 mass emissions (tons) for the compliance period as follows:

(1) For each operating hour, calculate the hourly CO2 mass (tons) according to paragraph (a)(3) or (4) of this section, except that a complete data record is required, *i.e.*, CO2 mass emissions must be reported for each operating hour. Therefore, substitute data values recorded under part 75 of this chapter for CO2 concentration, stack gas flow rate, stack gas moisture content, fuel flow rate and/or GCV shall be used in the calculations; and

(2) Sum all of the hourly CO2 mass emissions values over the entire compliance period.

(3) The owner or operator of an affected EGU must install, calibrate, maintain, and operate a sufficient number of watt meters to continuously measure and record on an hourly basis net electric output. Measurements must be performed using 0.2 accuracy class electricity metering instrumentation and calibration procedures as specified under ANSI Standards No. C12.20.

Further, the owner or operator of an affected EGU that is a combined heat and power facility must install, calibrate, maintain and operate equipment to continuously measure and record on an hourly basis useful thermal output and, if applicable, mechanical output, which are used with net electric output to determine net energy output (P,,,t). The owner or operator must calculate net energy output according to paragraphs (a)(5)(i)(A) and (B) of this section.

(c) Your plan must require the owner or operator of each affected EGU covered by your plan to maintain the records, as described in paragraphs (b)(1) and (2) of this section, for at least 5 years following the date of each compliance period, occurrence, measurement, maintenance, corrective action, report, or record.

(1) ~~**An**~~**The owner or operator of an** affected EGU must maintain each record on site for at least 2 years after the date of each **compliance period,** occurrence, measurement, maintenance, corrective action, report, or record, **whichever is latest,** according to

§ 60.7. ~~**An**~~**The owner or operator of an** affected EGU may maintain the records off site and electronically for the remaining year(s).

~~**(c) An affected EGU must include in a report required by the state plan covering each compliance period all hourly CO2 emissions and all hourly net electric output and all hourly net energy output measurements for a CHP facility calculated from data monitored according to paragraph (a) of this section.**~~

(2) The owner or operator of an affected EGU must keep all of the following records, in a form suitable and readily available for expeditious review:

(i) All documents, data files, and calculations and methods used to demonstrate compliance with an affected EGU's emission standard under § 60.5775.

(ii) Copies of all reports submitted to the State under paragraph (c) of this section.

(iii) Data that are required to be recorded by 40 CFR part 75 subpart F.

(iv) Data with respect to any ERCs generated by the affected EGU or used by the affected EGU in its compliance demonstration including the information in paragraphs (c)(2)(iv)(A) and (B) of this section.

(A) All documents related to any ERCs used in a compliance demonstration, including each eligibility application, EM&V plan, M&V report, and independent verifier verification report associated with the issuance of each specific ERC.

(B) All records and reports relating to the surrender and retirement of ERCs for compliance with this regulation, including the date each individual ERC with a unique serial identification number was surrendered and/or retired.

(d) Your plan must require the owner or operator of an affected EGU covered by your plan to include in a report submitted to you at the end of each compliance period the information in paragraphs (d)(1) through (5) of this section.

(1) Owners or operators of an affected EGU must include in the report all hourly CO2 emissions, for each affected EGU (or group of affected EGUs that share a monitored common stack).

(2) For rate-based standards, each report must include:

(i) The hourly CO2 mass emission rate values (tons/hr) and unit (or stack) operating times, (as monitored and reported according to part 75 of this chapter), for each valid operating hour in the compliance period;

(ii) The net electric output and the net energy output $_{(P,,,t)}$ values for each valid operating hour in the compliance period;

(iii) The calculated CO2 mass emissions (lb) for each valid operating hour in the compliance period;

(iv) The sum of the hourly net energy output values and the sum of the hourly CO2 mass emissions values, for all of the valid operating hours in the compliance period;

(v) ERC replacement generation (if any), properly justified (see paragraph (c)(5) of this section); and

(vi) The calculated CO2 mass emission rate for the compliance period (lbs/net MWh).

(3) For mass-based standards, each report must include:

(i) The hourly CO_2 mass emission rate value (tons/hr) and unit (or stack) operating time, as monitored and reported according to part 75 of this chapter, for each unit or stack operating hour in the compliance period;

(ii) The calculated CO_2 mass emissions (tons) for each unit or stack operating hour in the compliance period;

(iii) The sum of the CO_2 mass emissions (tons) for all of the unit or stack operating hours in the compliance period;

(iv) The net electric output and the net energy output $_{(P,,,t)}$ values for each unit or stack operating hour in the compliance period; and

(v) The sum of the hourly net energy output values for all of the unit or stack operating hours in the compliance period.

(vi) Notwithstanding the requirements in paragraphs (c)(3)(i) through (c)(3)(iii) of this section, if the compliance period is a discrete number of calendar years (e.g., one year, three years), in lieu of reporting the information specified in those paragraphs, the owner or operator may report:

(A) The cumulative annual CO_2 mass emissions (tons) for each year of the compliance period, derived from the electronic emissions report for the fourth calendar quarter of that year, submitted to EPA under § 75.64(a) of this chapter; and

(B) The sum of the cumulative annual CO_2 mass emissions values from paragraph (c)(3)(v)(A) of this section, if the compliance period includes multiple years.

(4) For each affected EGU's compliance period, the report must also include the applicable emission standard and demonstration that it met the emission standard. An owner or operator must also include in the report the affected EGU's calculated emission performance as a CO_2 emission rate or cumulative mass in units of the emission standard required in §§ 60.5790(b) through (c) and 60.5855, as applicable.

(5) If the owner or operator of an affected EGU is complying with an emission standard by using ERCs, they must include in the report a list of all unique ERC serial numbers that were retired in the compliance period, and, for each ERC, the date an ERC was surrendered and retired and

eligible resource identification information sufficient to demonstrate that it meets the requirements of § 60.5800 and qualifies to be issued ERCs (including location, type of qualifying generation or savings, date commenced generating or saving, and date of generation or savings for which the ERC was issued).

(6) If the owner or operator of an affected EGU is complying with an emission standard by using allowances, they must include in the report a list of all unique allowance serial numbers that were retired in the compliance period, and, for each allowance, the date an allowance was surrendered and retired and if the allowance was a set-aside allowance the eligible resource identification information sufficient to demonstrate that it meets the requirements of § 60.5815(c) and qualifies to be issued set-aside allowances (including location, type of qualifying generation or savings, date commenced generating or saving, and date of generation or savings for which the allowance was issued).

(e) The owner or operator of an affected EGU must follow any additional requirements for monitoring, recordkeeping and reporting in a plan that are required under § 60.5745(a)(4), if applicable.

(f) If an affected EGU captures CO2 to meet the applicable emission limit, the owner or operator must report in accordance with the requirements of 40 CFR part 98 subpart PP and either:

(1) Report in accordance with the requirements of 40 CFR part 98 subpart RR, if injection occurs on-site;

(2) Transfer the captured CO2 to an EGU or facility that reports in accordance with the requirements of 40 CFR part 98 subpart RR, if injection occurs off-site; or

(3) Transfer the captured CO2 to a facility that has received an innovative technology waiver from EPA pursuant to paragraph (g) of this section.

(g) Any person may request the Administrator to issue a waiver of the requirement that captured CO2 from an affected EGU be transferred to a facility reporting under 40 CFR part 98 subpart RR. To receive a waiver, the applicant must demonstrate to the Administrator that its technology will store captured CO2 as effectively as geologic sequestration, and that the proposed technology will not cause or contribute to an unreasonable risk to public health, welfare, or safety. In making this determination, the Administrator shall consider (among other factors) operating history of the technology, whether the technology will increase emissions or other releases of any pollutant other than CO2, and permanence of the CO2 storage. The Administrator may test the system itself, or require the applicant to perform any tests considered by the Administrator to be necessary to show the technology's effectiveness, safety, and ability to store captured CO2 without release. The Administrator may grant conditional approval of a technology, the approval conditioned on monitoring and reporting of operations. The Administrator may also withdraw approval of the waiver on evidence of releases of CO2 or other pollutants. The Administrator will provide notice to the public of any application under this provision, and provide public notice of any proposed action on a petition before the Administrator takes final action.

Recordkeeping and Reporting Requirements

§ ~~60.5810~~60.5865 What are my ~~state~~recordkeeping requirements?~~recordkeeping requirements?~~

(a) ~~States~~You must keep records of all information relied upon in support of any demonstration of plan components, plan requirements, supporting documentation, State measures, and the status of meeting the plan requirements defined in the ~~state~~ plan ~~on an annual basis during~~for each interim step and the interim ~~plan performance~~ period ~~from 2020–2029~~. After 2029 ~~states~~, States must keep records of all information ~~that is used to~~relied upon in support of any continued ~~effort to meet~~demonstration that the final ~~emissions~~CO2 emission performance ~~goal~~rates or CO2 emissions goals are being achieved.

(b) ~~States~~You must keep records of all data submitted by the owner or operator of each affected ~~entity~~EGU that is used to determine compliance with each affected ~~entity's~~EGU emissions standard or requirements in an approved State plan, consistent with the affected EGU requirements listed in § 60.5860.

(c) If ~~a state~~your State has a requirement for all hourly CO2 emissions and net generation information to be used to calculate compliance with an annual emissions standard for affected EGUs, any information that is submitted by the owners or operators of affected EGUs to the EPA electronically pursuant to requirements in Part 75 ~~would meet~~meets the recordkeeping requirement of this section and ~~a state would~~you are not ~~need~~required to keep records of information that would be in duplicate of paragraph (b) of this section.

(d) ~~A state~~You must keep records at a minimum for ~~20~~10 years~~.~~, for the interim period, and 5 years, for the final period, from the date the record is used to determine compliance with an emissions standard, plan requirement, CO_2 emission performance rate or CO_2 emissions goal. Each record must be in a form suitable and readily available for expeditious review.

§ ~~60.5815~~60.5870 What are my ~~state~~ reporting and notification requirements?

(a) In lieu of the annual report required under § 60.25(e) and (f) of this part, you must report the information in paragraphs (b) through (f) of this section.

(~~a~~b) You must submit ~~an annual~~a report covering each interim step within the interim period and each of the final 2-calendar year periods due no later than July 1 of the ~~following~~ year~~, starting July 1 2021. The annual~~ following the end of the period. The interim period reporting starts with a report covering interim step 1 due no later than July 1, 2025. The final period reports start with a biennial report covering the first final reporting period (which is due by July 1, 2032), a 2-calendar year average of emissions or cumulative sum of emissions used to determine compliance with the final CO_2 emission performance rate or CO_2 emission goal (as applicable). The report must include the ~~following:~~information in paragraphs (b)(1) through (4) of this section.

~~(1) The level of emissions performance achieved by all affected entities and identification of whether affected entities are on schedule to meet the applicable level of emissions performance for affected entities during the plan performance period and compliance periods, as specified in the plan.~~

(~~2~~1) The ~~level of~~report must include the emissions performance achieved by all affected EGUs during the reporting period, ~~and prior reporting periods, expressed as~~consistent with the plan approach according to § 60.5745(a), and identification of whether each affected ~~average CO2 emissions rate or total mass CO2 emissions, consistent with the plan approach, and identification of whether~~EGU is in compliance with its emission standard and whether the collective of all affected EGUs covered by the State are on schedule to meet the applicable ~~level of emissions~~CO2 emission performance ~~for affected EGUs~~rate or emission goal during the ~~plan~~ performance ~~period~~periods and compliance periods, as specified in the plan.

(2) The report must include a comparison of the CO2 emission performance rate or CO2 emission goal identified in the State plan for the applicable interim step period versus the actual average, cumulative, or adjusted CO2 emission performance (as applicable) achieved by all affected EGUs.

(i) For interim step 3, you do not need to include a comparison between the applicable interim step 3 CO2 emission performance rate or emission goal; you must only submit the average, cumulative or adjusted CO2 emission performance (as applicable) of your affected EGUs during that period in units of your applicable CO2 emission performance rate or emission goal.

~~(3) A list of affected entities and their compliance status with the applicable emissions standards specified in the state plan.~~

~~(4) A list of all affected EGUs and their reported CO2 emissions performance for each compliance period during the reporting period, and prior reporting periods.~~

(~~5~~3) ~~All~~The report must include all other required information, as specified in your ~~state~~State plan according to § 60.5740(a)(~~9~~5).

~~(6) All information required by § 60.5775(c).~~

~~(b) For each two-year period in § 60.5775(c)(1), you must compare the average CO2 emission performance achieved by affected entities in the state versus the CO2 emission performance projected in the state plan. If actual emission performance is greater than 10 percent in excess to projected plan performance for a two-year comparison period, you must explain the reasons for the deviation and specify the corrective actions that will be taken to ensure that the required interim and final levels of emission performance in the plan will be met. The information required in this paragraph must be included in the annual report required by paragraph (a) of this section.~~

(4) If applicable, the report must include a program review that your State has conducted that addresses all aspects of the administration of the State plan and overall program, including State

evaluations and regulatory decisions regarding eligibility applications for ERC resources and M&V reports (and associated EM&V activities), and State issuance of ERCs. The program review must assess whether the program is being administered properly in accordance with the approved plan, whether reported annual MWh of generation and savings from qualified ERC resources are being properly quantified, verified, and reported in accordance with approved EM&V plans, and whether appropriate records are being maintained. The program review must also address determination of the eligibility of verifiers by the State and the conduct of independent verifiers, including the quality of verifier reviews.

(c) If your plan relies upon State measures, in lieu of or in addition to emission standards, then you must submit an annual report to the EPA in addition to the reports required under paragraph (b) of this section for the interim period. In the final period, you must submit biennial reports consistent with those required under paragraph (b) of this section. The annual reports in the interim period must be submitted no later than July 1 following the end of each calendar year starting with 2022.

The annual and biennial reports must include the information in paragraphs (c)(1) and (2) of this section for the preceding year or two years, as applicable.

(1) You must include in your report the status of implementation of federally enforceable emission standards (if applicable) and State measures.

(2) You must include information regarding the status of the periodic programmatic milestones to show progress in program implementation. The programmatic milestones with specific dates for achievement must be consistent with the State measures included in the State plan submittal.

(d) If your plan includes the requirement for emission standards on your affected EGUs, then you must submit a notification, if applicable, in the report required under paragraph (b) of this section to the EPA if your affected EGUs trigger corrective measures as described in § 60.5740(a)(2)(i). If corrective measures are required and were not previously submitted with your state plan, you must follow the requirements in § 60.5785 for revising your plan to implement the corrective measures.

(e) If your plan relies upon State measures, in lieu of or in addition to emission standards, than you must submit a notification as required under paragraphs (e)(1) and (2) of this section.

(1) You must submit a notification in the report required under paragraph (c) of this section to the EPA if at the end of the calendar year your State did not meet a programmatic milestone included in your plan submittal. This notification must detail the implementation of the backstop required in your plan to be fully in place within 18 months of the due date of the report required in paragraph (b) of this section. In addition, the notification must describe the steps taken by the State to inform the affected EGUs in its State that the backstop has been triggered.

(2) You must submit a notification in the report required under paragraph (b) of this section to the EPA if you trigger the backstop as described in § 60.5740(a)(3)(i). This notification must detail the steps that will be taken by you to implement the backstop so that it is fully in place within 18 months of the due date of the report required in paragraph (b) of this section. In addition, the notification must describe the steps taken by the State to inform the affected EGUs that the backstop has been triggered.

(~~e~~f) You must include in your 2029 ~~annual~~ report (which is ~~subsequently~~ due by July 1, 2030) the calculation of average CO2 emissions rate, cumulative sum of CO2 emissions, or adjusted CO2 emissions rate (as applicable) over the ~~2020–2029~~ interim ~~performance period used to determine compliance with~~period and a comparison of those values to your interim CO2 emission performance ~~level~~rate or emission goal. The calculated value must be in units consistent with the approach you set in your plan for the interim ~~emission performance level~~period.

~~(d) You must include in each report, starting with the 2032 annual report (which is subsequently due by July 1, 2033), a 3-calendar year rolling average used to determine compliance with the final emission performance level. The calculated value must be in units consistent with your final emission performance level.~~

(g) The notifications listed in paragraphs (g)(1) through (3) of this section are required for the reliability safety valve allowed in § 60.5785(e).

(1) As required under § 60.5785(e), you must submit an initial notification to the appropriate EPA regional office within 48 hours of an unforeseen, emergency situation. The initial notification must:

(i) Include a full description, to the extent that it is known, of the emergency situation that is being addressed;

(ii) Identify the affected EGU or EGUs that are required to run to assure reliability; and

(iii) Specify the modified emission standards at which the identified EGU or EGUs will operate.

(2) Within 7 days of the initial notification in § 60.5870(g)(1), the State must submit a second notification to the appropriate EPA regional office that documents the initial notification. If the State fails to submit this documentation on a timely basis, the EPA will notify the State, which must then notify the affected EGU(s) that they must operate or resume operations under the original approved State plan emission standards. This notification must include the following:

(i) A full description of the reliability concern and why an unforeseen, emergency situation that threatens reliability requires the affected EGU or EGUs to operate under modified emission standards from those originally required in the State plan including discussion of why the flexibilities provided under the state's plan are insufficient to address the concern;

(ii) A description of how the State is coordinating or will coordinate with relevant reliability coordinators and planning authorities to alleviate the problem in an expedited manner;

(iii) An indication of the maximum time that the State anticipates the affected EGU or EGUs will need to operate in a manner inconsistent with its or their obligations under the State's approved plan;

(iv) A written concurrence from the relevant reliability coordinator and/or planning authority confirming the existence of the imminent reliability threat and supporting the temporary modification request or an explanation of why this kind of concurrence cannot be provided;

(v) The modified emission standards or levels that the affected EGU or EGU will be operating at for the remainder of the 90-day period if it has changed from the initial notification; and

(vi) Information regarding any systemwide or other analysis of the reliability concern conducted by the relevant planning authority, if any.

(3) At least 7 days before the end of the 90-day reliability safety valve period, the State must notify the appropriate EPA regional office that either:

(i) The reliability concern has been addressed and the affected EGU or EGUs can resume meeting the original emission standards in the State plan approved prior to the short-term modification; or

(ii) There still is a serious, ongoing reliability issue that necessitates the affected EGU or EGUs to emit beyond the amount allowed under the State plan. In this case, the State must provide a notification to the EPA that it will be submitting a State plan revision according to paragraph § 60.5785(a) of this section to address the reliability issue. The notification must provide the date by which a revised State plan will be submitted to EPA and documentation of the ongoing emergency with a written concurrence from the relevant reliability coordinator and/or planning authority confirming the continuing urgent need for the affected EGU or EGUs to operate beyond the requirements of the State plan and that there is no other reasonable way of addressing the ongoing reliability emergency but for the affected EGU or EGUs to operate under an alternative emission standard than originally approved under the State plan. After the initial 90-day period, any excess emissions beyond what is authorized in the original approved State plan will count against the State's overall CO2 emission goal or emission performance rate for affected EGUs.

§ 60.5875 How do I submit information required by these Emission Guidelines to the EPA?

(a) You must submit to the EPA the information required by these emission guidelines following the procedures in paragraphs (b) through (e) of this section.

(b) All negative declarations, State plan submittals, supporting materials that are part of a State plan submittal, any plan revisions, and all State reports required to be submitted to the EPA by the State plan must be reported through EPA's State Plan Electronic Collection System (SPeCS).

SPeCS is a web accessible electronic system accessed at the EPA's Central Data Exchange (CDX) (*http://www.epa.gov/cdx/*). States who claim that a State plan submittal or supporting documentation includes confidential business information (CBI) must submit that information on a compact disc, flash drive, or other commonly used electronic storage media to the EPA. The electronic media must be clearly marked as CBI and mailed to U.S. EPA/OAQPS/CORE CBI Office, Attention: State and Local Programs Group, MD C539–01, 4930 Old Page Rd., Durham, NC 27703.

(c) Only a submittal by the Governor or the Governor's designee by an electronic submission through SPeCS shall be considered an official submittal to the EPA under this subpart. If the Governor wishes to designate another responsible official the authority to submit a State plan, the EPA must be notified via letter from the Governor prior to the September 6, 2016, deadline for plan submittal so that the official will have the ability to submit the initial or final plan submittal in the SPeCS. If the Governor has previously delegated authority to make CAA submittals on the Governor's behalf, a State may submit documentation of the delegation in lieu of a letter from the Governor. The letter or documentation must identify the designee to whom authority is being designated and must include the name and contact information for the designee and also identify the State plan preparers who will need access to SPeCS. A State may also submit the names of the State plan preparers via a separate letter prior to the designation letter from the Governor in order to expedite the State plan administrative process. Required contact information for the designee and preparers includes the person's title, organization and email address.

(d) The submission of the information by the authorized official must be in a non-editable format. In addition to the non-editable version all plan components designated as federally enforceable must also be submitted in an editable version. Following initial plan approval, States must provide the EPA with an editable copy of any submitted revision to existing approved federally enforceable plan components, including State plan backstop measures. The editable copy of any such submitted plan revision must indicate the changes made at the State level, if any,

to the existing approved federally enforceable plan components, using a mechanism such as redline/strikethrough. These changes are not part of the State plan until formal approval by EPA.

(e) You must provide the EPA with non-editable and editable copies of any submitted revision to existing approved federally enforceable plan components, including State plan backstop measures. The editable copy of any such submitted plan revision must indicate the changes made at the State level, if any, to the existing approved federally enforceable plan components, using a mechanism such as redline/strikethrough. These changes are not part of the State plan until formal approval by EPA.

Definitions

§ ~~60.5820~~60.5880 What definitions apply to this subpart?

As used in this subpart, all terms not defined herein will have the meaning given them in the Clean Air Act and in subparts A ~~(General Provisions) and~~**,** B**, and TTTT,** of this part.

Adjusted CO2 Emission Rate Means

(1) For an affected EGU, the reported CO2 emission rate of an affected EGU, adjusted as described in § 60.5790(c)(1) to reflect any ERCs used by an affected EGU to demonstrate compliance with its CO2 emission standards; or

(2) For a State (or states in a multistate plan) calculating a collective CO2 emission rate achieved under the plan, the actual CO2 emission rate during a plan reporting period of the affected EGUs subject to the rate specified in the plan, adjusted by the ERCs used for compliance by those EGUs (total CO2 mass divided by the sum of the total MWh and ERCs).

Affected electric generating unit or *Affected EGU* means a steam generating unit, ~~an~~**integrated gasification combined cycle (**IGCC ~~facility~~**)**, or ~~a~~ stationary combustion turbine that meets the **relevant** applicability conditions in section § ~~60.5795~~**60.5845**.

~~*Affected Entity* shall mean any of the following: An affected EGU, or another entity with obligations under this subpart for the purpose of meeting the emissions performance goal requirements in these emission guidelines.~~

***Allowance* means an authorization for each specified unit of actual CO2 emitted from an affected EGU or a facility during a specified period.**

***Allowance system* means a control program under which the owner or operator of each affected EGU is required to hold an allowance for each specified unit of CO2 emitted from that affected EGU or facility during a specified period and which limits the total amount of such allowances for a specified period and allows the transfer of such allowances.**

***Annual capacity factor* means the ratio between the actual heat input to an EGU during a calendar year and the potential heat input to the EGU had it been operated for 8,760 hours during a calendar year at the base load rating.**

Base load rating means the maximum amount of heat input (fuel) that ~~a steam generating unit~~an EGU can combust on a ~~steady state~~steady-state basis, as determined by the physical design and characteristics of the ~~steam generating unit~~EGU at ISO conditions. For a stationary combustion turbine, *base load rating* ~~means 100 percent of the design heat input capacity of the simple cycle portion of the stationary combustion turbine at ISO conditions (~~includes the heat input from duct burners~~is not included)~~.

***Biomass* means biologically based material that is living or dead (*e.g.*, trees, crops, grasses, tree litter, roots) above and below ground, and available on a renewable or recurring basis. Materials that are biologically based include non-fossilized, biodegradable organic material originating from modern or contemporarily grown plants, animals, or microorganisms (including plants, products, byproducts and residues from agriculture, forestry, and related activities and industries, as well as the non-fossilized and biodegradable organic fractions of industrial and municipal wastes, including gases and liquids recovered from the decomposition of non-fossilized and biodegradable organic material).**

CO2 ~~*emissions performance*~~*emission* *goal* means ~~the~~a statewide rate-based CO2 ~~emissions performance~~emission goal or mass-based CO2 emission goal specified ~~for a state in Table 1 of this subpart, or a translated mass-based form of that goal~~in § 60.5855.

~~*Coal* means all solid fuels classified as anthracite, bituminous, subbituminous, or lignite by the American Society of Testing and Materials in ASTM D388 (incorporated by reference, see § 60.17),~~

~~**coal refuse, and petroleum coke. Synthetic fuels derived from coal for the purpose of creating useful heat, including but not limited to solvent-refined coal, gasified coal (not meeting the definition of natural gas), coal-oil mixtures, and coal-water mixtures are included in this definition for the purposes of this subpart.**~~

Combined cycle ~~facility~~unit means an electric generating unit that uses a stationary combustion turbine from which the heat from the turbine exhaust gases is recovered by a heat recovery steam generating unit to generate additional electricity.

Combined heat and power ~~facility~~unit or *CHP ~~facility~~unit, (*also known as "cogeneration") means an electric generating unit that ~~that use~~uses a steam-generating unit or stationary combustion turbine to simultaneously produce both electric (or mechanical) and useful thermal output from the same primary energy source.

Compliance period **means a discrete time period for an affected EGU to comply with either an emission standard or State measure.**

Demand-side energy efficiency project **means an installed piece of equipment or system, a modification of an existing piece of equipment or system, or a strategy intended to affect consumer electricity-use behavior, that results in a reduction in electricity use (in MWh) at an end-use facility, premises, or equipment connected to the electricity grid.**

Derate **means a decrease in the available capacity of an electric generating unit, due to a system or equipment modification or to discounting a portion of a generating unit's capacity for planning purposes.**

Eligible resource **means a resource that meets the requirements of § 60.5800(a).**

Emission Rate Credit or ERC **means a tradable compliance instrument that meets the requirements of § 60.5790(c).**

EM&V plan **means a plan that meets the requirements of § 60.5830.**

ERC tracking system **means a system for the issuance, surrender and retirement of ERCs that meets the requirements of § 60.5810.**

~~*Compliance*~~*Final period* means the period ~~of time, set forth by a state in its state plan, during which each affected entity must demonstrate compliance with an applicable emissions standard, and shall be no greater than a three year period for a mass-based plan, and shall be no~~that begins on January 1, 2030, and continues thereafter. The final period is comprised of final reporting periods, each of which may be no longer than two calendar years (with a calendar year beginning on January 1 and ending on December 31).

Final reporting period means an increment of plan performance within the final period, with each final reporting period being no longer than two calendar years (with a calendar year beginning on January 1 and ending on December 31), with the first final reporting period in the final period beginning on January 1, 2030, and ending no later than December 31, 2031.~~greater than a one year period for a rate-based plan.~~

~~*Emission performance level* in a state plan means the level of emissions performance for affected entities specified in a state plan, according to § 60.5740.~~

~~*Emission standard* means in addition to the definition in § 60.21, any requirement applicable to any affected entity other than an affected source that has the effect of reducing utilization of one or more affected sources, thereby avoiding emissions from such sources, including, for example, renewable energy and demand-side energy efficiency measures requirements.~~

~~*Excess emissions* means a specified averaging period over which the CO2 emissions rate is higher than an applicable emissions standard or an averaging period during which an affected EGU is not in compliance with any other emission limitation specified in an emission standard.~~

~~*Existing state program, requirement, or measure* means, in the context of a state plan, a regulation, requirement, program, or measure administered by a state, utility, or other entity that is currently established. This may include a regulation or other legal requirement that includes past, current, and future obligations, or current programs and measures that are in place and are anticipated to be continued or expanded in the future, in accordance with established plans. An existing state program, requirement, or measure may have past, current, and future impacts on EGU CO2 emissions.~~

Fossil fuel means natural gas, petroleum, coal, and any form of solid **fuel**, liquid **fuel**, or gaseous fuel derived from such material for the purpose of creating useful heat.

~~***Gaseous fuel*** **means any fuel that is present as a gas at ISO conditions and includes, but is not limited to, natural gas, refinery fuel gas, process gas, coke-oven gas, synthetic gas, and gasified coal.**~~

Heat recovery steam generating unit (HRSG) means a unit in which hot exhaust gases from the combustion turbine engine are routed in order to extract heat from the gases and generate useful output. Heat recovery steam generating units can be used with or without duct burners.

Independent verifier **means a person (including any individual, corporation, partnership, or association) who has the appropriate technical and other qualifications to provide verification reports. The independent verifier must not have, or have had, any direct or indirect financial or other interest in the subject of its verification report or ERCs that could impact their impartiality in performing verification services.**

Integrated gasification combined cycle facility or *IGCC* ~~*facility*~~ means a combined cycle facility that is designed to burn fuels containing 50 percent (by heat input) or more solid-derived fuel not meeting the definition of natural gas plus any integrated equipment that provides electricity or useful thermal output to either the affected facility or auxiliary equipment. The Administrator may waive the 50 percent solid-derived fuel requirement during periods of the gasification system construction, startup and commissioning, shutdown, or repair. No solid fuel is directly burned in the unit during operation.

Interim period **means the period of eight calendar years from January 1, 2022, to December 31, 2029. The interim period is composed three interim steps, interim step 1, interim step 2, and interim step 3.**

Interim step **means an increment of plan performance within the interim period.**

Interim step 1 **means the period of three calendar years from January 1, 2022, to December 31, 2024.**

***Interim step 2* means the period of three calendar years from January 1, 2025, to December 31, 2027.**

***Interim step 3* means the period of two calendar years from January 1, 2028, to December 31, 2029.**

ISO conditions means 288 Kelvin (15°C), 60 percent relative humidity and 101.3 kilopascals pressure.

~~***Liquid fuel* means any fuel that is present as a liquid at ISO conditions and includes, but is not limited to, distillate oil and residual oil.**~~

***M&V report* means a report that meets the requirements of § 60.5835.**

Mechanical output means the useful mechanical energy that is not used to operate the affected facility, generate electricity and/or thermal output, or to enhance the performance of the affected facility. Mechanical energy measured in horsepower hour ~~should~~**must** be converted into MWh by multiplying it by 745.7 then dividing by 1,000,000.

***Nameplate capacity* means, starting from the initial installation, the maximum electrical generating output that a generator, prime mover, or other electric power production equipment under specific conditions designated by the manufacturer is capable of producing (in MWe, rounded to the nearest tenth) on a steady-state basis and during continuous operation (when not restricted by seasonal or other deratings) as of such installation as specified by the manufacturer of the equipment, or starting from the completion of any subsequent physical change resulting in an increase in the maximum electrical generating output that the equipment is capable of producing on a steady-state basis and during continuous operation (when not restricted by seasonal or other deratings), such increased maximum amount (in MWe, rounded to the nearest tenth) as of such completion as specified by the person conducting the physical change.**

Natural gas means a fluid mixture of hydrocarbons (*e.g.,* methane, ethane, or propane), composed of at least 70 percent methane by volume or that has a gross calorific value between 35 and 41 megajoules (MJ) per dry standard cubic meter (950 and 1,100 Btu per dry standard cubic foot), that maintains a gaseous ~~state~~**State** under ISO conditions. In addition, natural gas contains 20.0 grains or less of total sulfur per 100 standard cubic feet. Finally, natural gas does not include the following gaseous fuels:

Landfill gas, digester gas, refinery gas, sour gas, blast furnace gas, coal-derived gas, producer gas, coke oven gas, or any gaseous fuel produced in a process which might result in highly variable sulfur content or heating value.

Net allowance export/import **means a net transfer of CO2 allowances during an interim step, the interim period, or a final reporting period which represents the net number of CO2 allowances (issued by a State) that are transferred from the compliance accounts of affected EGUs in that state to the compliance accounts of affected EGUs in another State. This net transfer is determined based on compliance account holdings at the end of the plan performance period. Compliance account holdings, as used here, refer to the number of CO2 allowances surrendered for compliance during a plan performance period, as well as any remaining CO2 allowances held in a compliance account as of the end of a plan performance period.**

~~*Net-electric*~~*Net electric output* means the amount of gross generation the generator(s) produce (including, but not limited to, output from steam turbine(s), combustion turbine(s), and gas expander(s)), as measured at the generator terminals, less the electricity used to operate the plant (*i.e.,* auxiliary loads); such uses include fuel handling equipment, pumps, fans, pollution control equipment, other electricity needs, and transformer losses as measured at the transmission side of the step up transformer (*e.g.,* the point of sale).

Net energy output means:

(1) The net electric or mechanical output from the affected facility, plus ~~75~~**100** percent of the useful thermal output measured relative to SATP conditions that is not used to generate additional electric or mechanical output or to enhance the performance of the unit (*e.g.,* steam delivered to an industrial process for a heating application).

(2) For combined heat and power facilities where at least 20.0 percent of the total gross **or net** energy output consists of electric or direct mechanical output and **at least** 20.0 percent of the total gross **or net** energy output consists of useful thermal output on a **12-operating month** rolling ~~3-year~~**average** basis, the net electric or mechanical output from the affected ~~facility~~**EGU** divided by

0.95, plus ~~75~~100 percent of the useful thermal output ~~measured relative to SATP conditions that is not used to generate additional electric or mechanical output or to enhance the performance of the unit~~; (*e.g.,* steam delivered to an industrial process for a heating application).

~~***Petroleum*** **means crude oil or a fuel derived from crude oil, including, but not limited to, distillate and residual oil.**~~

~~***Solid fuel*** **means any fuel that has a definite shape and volume, has no tendency to flow or disperse under moderate stress, and is not liquid or gaseous at ISO conditions. This includes, but is not limited to, coal, biomass, and pulverized solid fuels.**~~

Programmatic milestone **means the implementation of measures necessary for plan progress, including specific dates associated with such implementation. Prior to January 1, 2022, programmatic milestones are applicable to all state plan approaches and measures. Subsequent to January 1, 2022, programmatic milestones are applicable to state measures.**

Qualified biomass **means a biomass feedstock that is demonstrated as a method to control increases of CO2 levels in the atmosphere.**

Standard ambient temperature and pressure (SATP) conditions means 298.15 Kelvin (25 °C, 77 °F)) and 100.0 kilopascals (14.504 psi, 0.987 atm) pressure. The enthalpy of water at SATP conditions is 50 Btu/lb.

State agent **means an entity acting on behalf of the State, with the legal authority of the State.**

State measures **means measures that are adopted, implemented, and enforced as a matter of State law. Such measures are enforceable only per State law, and are not included in and codified as part of the federally enforceable State plan.**

Stationary combustion turbine means all equipment, including but not limited to the turbine engine, the fuel, air, lubrication and exhaust gas systems, control systems (except emissions control equipment), heat recovery system, fuel compressor, heater, and/or pump, post-combustion emissions control technology, and any ancillary components and sub-components comprising any simple cycle stationary combustion turbine, any combined cycle combustion turbine, and any combined heat and power combustion turbine based system plus any integrated equipment that provides electricity or useful thermal output to the combustion turbine engine, heat recovery system or auxiliary equipment.

Stationary means that the combustion turbine is not self-propelled or intended to be propelled while performing its function. It may, however, be mounted on a vehicle for portability. If a stationary combustion turbine burns any solid fuel directly it is considered a steam generating unit.

Steam generating unit means any furnace, boiler, or other device used for combusting fuel and producing steam (nuclear steam generators are not included) plus any integrated equipment that provides electricity or useful thermal output to the affected facility or auxiliary equipment.

Uprate **means an increase in available electric generating unit power capacity due to a system or equipment modification.**

Useful thermal output means the thermal energy made available for use in any ~~**industrial or commercial process, or used in any**~~ heating ~~**or cooling**~~**application (*e.g.*, steam delivered to an industrial process for a heating** application, ~~**i.e., total**~~**including** thermal ~~**energy made available for processes and**~~**cooling** applications ~~**other than**~~**) that is not used for** electric generation, mechanical output at the affected ~~**facility**~~**EGU**, ~~**or**~~ to directly enhance the performance of the affected ~~**facility**~~**EGU** (*e.g.,* economizer output is not useful thermal output, but thermal energy used to reduce fuel moisture is considered useful thermal output)**, or to supply energy to a pollution control device at the affected EGU**. Useful thermal output for affected ~~**facilities**~~**EGU(s)** with no condensate return (or other thermal energy input to the affected ~~**facility**~~**EGU(s)**) or where measuring the energy in the condensate (or other thermal energy input to the affected ~~**facility**~~**EGU(s)**) would not meaningfully impact the emission rate calculation is measured against the energy in the thermal output at SATP conditions. Affected ~~**facilities**~~**EGU(s)** with meaningful energy in the condensate return (or other thermal energy input to the affected ~~**facility**~~**EGU**) must measure the energy in the condensate and subtract that energy relative to SATP conditions from the measured thermal output.

Valid data **means quality-assured data generated by continuous monitoring systems that are installed, operated, and maintained according to part 75 of this chapter. For CEMS, the initial certification requirements in § 75.20 of this chapter and appendix A to part 75 of this chapter must be met before quality-assured data are reported under this subpart; for on-going quality**

assurance, the daily, quarterly, and semiannual/annual test requirements in sections 2.1, 2.2, and 2.3 of appendix B to part 75 of this chapter must be met and the data validation criteria in sections 2.1.5, 2.2.3, and 2.3.2 of appendix B to part 75 of this chapter apply. For fuel flow meters, the initial certification requirements in section 2.1.5 of appendix D to part 75 of this chapter must be met before quality-assured data are reported under this subpart (except for qualifying commercial billing meters under section 2.1.4.2 of appendix D), and for on-going quality assurance, the provisions in section 2.1.6 of appendix D to part 75 of this chapter apply (except for qualifying commercial billing meters).

Waste-to-Energy means a process or unit (*e.g.*, solid waste incineration unit) that recovers energy from the conversion or combustion of waste stream materials, such as municipal solid waste, to generate electricity and/ or heat.

TABLE 1 TO SUBPART UUUU OF PART 60—~~STATE RATE-BASED~~ CO2 EMISSION PERFORMANCE ~~GOALS~~RATES
[Pounds of CO2 per net MWh]

Affected EGU	Interim rate	Final rate
Steam generating unit or integrated gasification combined cycle (IGCC)	1,534	1,305
Stationary combustion turbine	832	771

TABLE 2 TO SUBPART UUUU OF PART 60—STATEWIDE RATE-BASED CO2 EMISSION GOALS
[Pounds of CO2 per net MWh]

State	Interim	Final emission
Alabama	~~1.147~~1.157	~~1.059~~1.018
~~Alaska~~Arizona	~~1.097~~1.173	~~1.003~~1.031
~~Arizona~~Arkansas	~~735~~1.304	~~702~~1.130
~~Arkansas~~California	~~968~~907	~~910~~828
~~California~~	~~556~~	~~537~~
Colorado	~~1.159~~1.362	~~1.108~~1.174
Connecticut	~~597~~852	~~540~~786
Delaware	~~913~~1.023	~~841~~916
Florida	~~794~~1.026	~~740~~919
Georgia	~~891~~1.198	~~834~~1.049
~~Hawaii~~ Idaho	~~1.378~~832	~~1.306~~771
~~Idaho~~Illinois	~~244~~1,456	~~228~~1,245

TABLE 2 TO SUBPART UUUU OF PART 60—STATEWIDE RATE-BASED CO_2 EMISSION GOALS—Continued

[Pounds of CO_2 per net MWh]

~~Illinois~~State	~~1,366~~Interim	~~1,271~~Final
Indiana	~~1,607~~1,451	~~1,531~~1,242
Iowa	~~1,341~~1,505	~~1,301~~1,283
Kansas	~~1,578~~1,519	~~1,499~~1,293
Kentucky	~~1,844~~1,509	~~1,763~~1,286
Lands of the Fort Mojave Tribe	832	771
Lands of the Navajo Nation	1,534	1,305
Lands of the Uintah and Ouray Reservation	1,534	1,305
Louisiana	~~948~~1,293	~~883~~1,121
Maine	~~393~~842	~~378~~779
Maryland	~~1,347~~1,510	~~1,187~~1,287
Massachusetts	~~655~~902	~~576~~824
Michigan	~~1,227~~1,355	~~1,161~~1,169
Minnesota	~~911~~1,414	~~873~~1,213
Mississippi	~~732~~1,061	~~692~~945
Missouri	~~1,621~~1,490	~~1,544~~1,272
Montana	~~1,882~~1,534	~~1,771~~1,305
Nebraska	~~1,596~~1,522	~~1,479~~1,296
Nevada	~~697~~942	~~647~~855
New Hampshire	~~546~~947	~~486~~858
New Jersey	~~647~~885	~~531~~812
New Mexico	~~1,107~~1,325	~~1,048~~1,146
New York	~~635~~1,025	~~549~~918
North Carolina	~~1,077~~1,311	~~992~~1,136
North Dakota	~~1,817~~1,534	~~1,783~~1,305
Ohio	1,383	1,190
Oklahoma	1,223	1,068
Oregon	964	871
Pennsylvania	1,258	1,095
Rhode Island	832	771
South Carolina	1,338	1,156
South Dakota	1,352	1,167
Tennessee	1,411	1,211
Texas	1,188	1,042
Utah	1,368	1,179
Virginia	1,047	934
Washington	1,111	983
West Virginia	1,534	1,305
Wisconsin	1,364	1,176
Wyoming	1,526	1,299

TABLE 3 TO SUBPART UUUU OF PART 60—STATEWIDE MASS-BASED CO_2 EMISSION GOALS

[Short tons of CO_2]

State	Interim emission goal (2022–2029)	Final emission goals (2 year blocks starting with 2030–2031)
Alabama	497,682,304	113,760,948
Arizona	264,495,976	60,341,500
Arkansas	269,466,064	60,645,264
California	408,216,600	96,820,240
Colorado	267,103,064	59,800,794
Connecticut	57,902,920	13,883,046
Delaware	40,502,952	9,423,650
Florida	903,877,832	210,189,408
Georgia	407,408,672	92,693,692
Idaho	12,401,136	2,985,712
Illinois	598,407,008	132,954,314
Indiana	684,936,520	152,227,670
Iowa	226,035,288	50,036,272
Kansas	198,874,664	43,981,652
Kentucky	570,502,416	126,252,242
Lands of the Fort Mojave Tribe	4,888,824	1,177,038
Lands of the Navajo Nation	196,462,344	43,401,174
Lands of the Uintah and Ouray Reservation	20,491,560	4,526,862
Louisiana	314,482,512	70,854,046
Maine	17,265,472	4,147,884
Maryland	129,675,168	28,695,256
Massachusetts	101,981,416	24,209,494
Michigan	424,457,200	95,088,128

TABLE 3 TO SUBPART UUUU OF PART 60—STATEWIDE MASS-BASED CO_2 EMISSION GOALS—Continued

[Short tons of CO_2]

State	Interim emission goal (2022–2029)	Final emission goals (2 year blocks starting with 2030–2031)
Minnesota	203,468,736	45,356,736
Missouri	500,555,464	110,925,768
Mississippi	218,706,504	50,608,674
Montana	102,330,640	22,606,214
Nebraska	165,292,128	36,545,478
Nevada	114,752,736	27,047,168
New Hampshire	33,947,936	7,995,158
New Jersey	139,411,048	33,199,490
New Mexico	110,524,488	24,825,204
New York	268,762,632	62,514,858
North Carolina	455,888,200	102,532,468
North Dakota	189,062,568	41,766,464
Ohio	660,212,104	147,539,612
Oklahoma	356,882,656	80,976,398
Oregon	69,145,312	16,237,308
Pennsylvania	794,646,616	179,644,616
Rhode Island	29,259,080	7,044,450
South Carolina	231,756,984	51,997,936
South Dakota	31,591,600	7,078,962
Tennessee	254,278,880	56,696,792
Texas	1,664,726,728	379,177,684
Utah	212,531,040	47,556,386
Virginia	236,640,576	54,866,222
Washington	93,437,656	21,478,344
West Virginia	464,664,712	102,650,684
Wisconsin	250,066,848	55,973,976
Wyoming	286,240,416	63,268,824

TABLE 4 TO SUBPART UUUU OF PART 60— STATEWIDE MASS-BASED CO_2 GOALS PLUS NEW SOURCE CO_2 EMISSION COMPLEMENT

[Short tons of CO_2]

State	Interim emission goal (2022–2029)	Final emission goals (2 year blocks starting with 2030–2031)
Alabama	504,534,496	115,272,348
Arizona	275,895,952	64,760,392
Arkansas	272,756,576	61,371,058
California	430,988,824	105,647,270
Colorado	277,022,392	63,645,748
Connecticut	58,986,192	14,121,986
Delaware	41,133,688	9,562,772
Florida	917,904,040	213,283,190
Georgia	412,826,944	93,888,808
Idaho	13,155,256	3,278,026
Illinois	604,953,792	134,398,348
Indiana	692,451,256	153,885,208
Iowa	228,426,760	50,563,762
Kansas	200,960,120	44,441,644
Kentucky	576,522,048	127,580,002
Lands of the Fort Mojave Tribe	5,186,112	1,292,276
Lands of the Navajo Nation	202,938,832	45,911,608
Lands of the Uintah and Ouray Reservation	21,167,080	4,788,708
Louisiana	318,356,976	71,708,642
Maine	17,592,128	4,219,936
Maryland	131,042,600	28,996,872
Massachusetts	103,782,424	24,606,744
Michigan	429,446,408	96,188,604
Minnesota	205,761,008	45,862,346
Mississippi	221,990,024	51,332,926
Missouri	505,904,560	112,105,626
Montana	105,704,024	23,913,816
Nebraska	167,021,320	36,926,888
Nevada	120,916,064	29,436,214
New Hampshire	34,519,280	8,121,182
New Jersey	141,919,248	33,752,728
New Mexico	114,741,592	26,459,850

TABLE ~~1~~4 TO SUBPART UUUU OF PART 60—~~STATE RATE-BASED~~ STATEWIDE MASS-BASED CO_2 GOALS PLUS NEW SOURCE CO_2 EMISSION ~~PERFORMANCE GOALS~~ COMPLEMENT—Continued

[~~Pounds~~Short tons of CO_2 ~~per net MWh~~]

State	Interim emission goal (2022–2029)	Final ~~goal~~emission goals (2 year blocks starting with 2030–2031)
~~Ohio~~New York	~~1,452~~272,940,440	~~1,338~~63,436,364
North Carolina	461,424,928	103,753,712
North Dakota	191,025,152	42,199,354
Ohio	667,812,080	149,215,950
Oklahoma	~~931~~361,531,056	~~895~~82,001,704
Oregon	~~407~~72,774,608	~~372~~17,644,106
Pennsylvania	~~1,179~~804,705,296	~~1,052~~181,863,274
Rhode Island	~~822~~29,819,360	~~782~~7,168,032
South Carolina	~~840~~234,516,064	~~772~~52,606,510
South Dakota	~~800~~31,963,696	~~741~~7,161,036
Tennessee	~~1,254~~257,149,584	~~1,163~~57,329,988
Texas	~~853~~1,707,356,792	~~791~~396,210,498
Utah	~~1,378~~220,386,616	~~1,322~~50,601,386
Virginia	~~884~~240,240,880	~~810~~55,660,348
Washington	~~264~~97,691,736	~~215~~23,127,324
West Virginia	~~1,748~~469,488,232	~~1,620~~103,714,614
Wisconsin	~~1,281~~252,985,576	~~1,203~~56,617,764
Wyoming	~~1,808~~295,724,848	~~1,714~~66,945,204

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STATUTORY AND REGULATORY ADDENDUM

Except for the following, all applicable statutes and regulations are contained in the Addendum to the Opening Brief of Petitioners on Core Legal Issues, ECF 1599889, the Opening Brief of Petitioners on Procedural and Record-Based Issues, ECF 1599898, and the Reply Brief of Petitioners on Core Legal Issues, ECF __ (forthcoming).

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Federal Statutes

Clean Air Act, 42 U.S.C. §§ 7401, *et seq.* (2014)

CAA § 101(b), 42 U.S.C. § 7401(b) REPLY2-ADD-001

CAA § 307(d), 42 U.S.C. § 7607(d) REPLY2-ADD-002

42 U.S.C. §7401(b). Congressional findings and declaration of purpose

(b) DECLARATION

The purposes of this subchapter are—

(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. §7607(d). Administrative proceedings and judicial review

(D) RULEMAKING

(1) This subsection applies to—

(A) the promulgation or revision of any national ambient air quality standard under section 7409 of this title,

(B) the promulgation or revision of an implementation plan by the Administrator under section 7410(c) of this title,

(C) the promulgation or revision of any standard of performance under section 7411 of this title, or emission standard or limitation under section 7412(d) of this title, any standard under section 7412(f) of this title, or any regulation under section 7412(g)(1)(D) and (F) of this title, or any regulation under section 7412(m) or (n) of this title,

(D) the promulgation of any requirement for solid waste combustion under section 7429 of this title,

(E) the promulgation or revision of any regulation pertaining to any fuel or fuel additive under section 7545 of this title,

(F) the promulgation or revision of any aircraft emission standard under section 7571 of this title,

(G) the promulgation or revision of any regulation under subchapter IV–A of this chapter (relating to control of acid deposition),

(H) promulgation or revision of regulations pertaining to primary nonferrous smelter orders under section 7419 of this title (but not including the granting or denying of any such order),

(I) promulgation or revision of regulations under subchapter VI of this chapter (relating to stratosphere and ozone protection),

(J) promulgation or revision of regulations under part C of subchapter I of this chapter (relating to prevention of significant deterioration of air quality and protection of visibility),

(K) promulgation or revision of regulations under section 7521 of this title and test procedures for new motor vehicles or engines under section 7525 of this title, and the revision of a standard under section 7521(a)(3) of this title,

(L) promulgation or revision of regulations for noncompliance penalties under section 7420 of this title,

(M) promulgation or revision of any regulations promulgated under section 7541 of this title (relating to warranties and compliance by vehicles in actual use),

(N) action of the Administrator under section 7426 of this title (relating to interstate pollution abatement),

(O) the promulgation or revision of any regulation pertaining to consumer and commercial products under section 7511b(e) of this title,

(P) the promulgation or revision of any regulation pertaining to field citations under section 7413(d)(3) of this title,

(Q) the promulgation or revision of any regulation pertaining to urban buses or the clean-fuel vehicle, clean-fuel fleet, and clean fuel programs under part C of subchapter II of this chapter,

(R) the promulgation or revision of any regulation pertaining to nonroad engines or nonroad vehicles under section 7547 of this title,

(S) the promulgation or revision of any regulation relating to motor vehicle compliance program fees under section 7552 of this title,

(T) the promulgation or revision of any regulation under subchapter IV–A of this chapter (relating to acid deposition),

(U) the promulgation or revision of any regulation under section 7511b(f) of this title pertaining to marine vessels, and

(V) such other actions as the Administrator may determine.

The provisions of section 553 through 557 and section 706 of title 5 shall not, except as expressly provided in this subsection, apply to actions to which this subsection applies. This subsection shall not apply in the case of any rule or circumstance referred to in subparagraphs (A) or (B) of subsection 553(b) of title 5.

(2) Not later than the date of proposal of any action to which this subsection applies, the Administrator shall establish a rulemaking docket for such action (hereinafter in this subsection referred to as a “rule”). Whenever a rule applies only within a particular State, a second (identical) docket shall be simultaneously established in the appropriate regional office of the Environmental Protection Agency.

(3) In the case of any rule to which this subsection applies, notice of proposed rulemaking shall be published in the Federal Register, as provided under section 553(b) of title 5, shall be accompanied by a statement of its basis and purpose and shall specify the period available for public comment (hereinafter referred to as the “comment period”). The notice of proposed rulemaking shall also state the docket number, the location or locations of the docket, and the times it will be open to public inspection. The statement of basis and purpose shall include a summary of—

(A) the factual data on which the proposed rule is based;

(B) the methodology used in obtaining the data and in analyzing the data; and

(C) the major legal interpretations and policy considerations underlying the proposed rule.

The statement shall also set forth or summarize and provide a reference to any pertinent findings, recommendations, and comments by the Scientific Review Committee established under section 7409(d) of this title and the National Academy of Sciences, and, if the proposal differs in any important respect from any of these recommendations, an explanation of the reasons for such differences. All data, information, and documents referred to in this paragraph on which the proposed rule relies shall be included in the docket on the date of publication of the proposed rule.

(4)(A) The rulemaking docket required under paragraph (2) shall be open for inspection by the public at reasonable times specified in the notice of proposed rulemaking. Any person may copy documents contained in the docket. The Administrator shall provide copying facilities which may be used at the expense of the person seeking copies, but the Administrator may waive or reduce such expenses in such instances as the public interest requires. Any person may request copies by mail if the person pays the expenses, including personnel costs to do the copying.

(B)(i) Promptly upon receipt by the agency, all written comments and documentary information on the proposed rule received from any person for inclusion in the docket during the comment period shall be placed in the docket. The transcript of public hearings, if any, on the proposed rule shall also be included in the docket promptly upon receipt from the person who transcribed such hearings. All documents which become available after the proposed rule has been published and which the Administrator determines are of central relevance to the rulemaking shall be placed in the docket as soon as possible after their availability.

(ii) The drafts of proposed rules submitted by the Administrator to the Office of Management and Budget for any interagency review process prior to proposal of any such rule, all documents accompanying such drafts, and all written comments thereon by other agencies and all written responses to such written comments by the Administrator shall be placed in the docket no later than the date of proposal of the rule. The drafts of the final rule submitted for such review process prior to promulgation and all such written comments thereon, all documents accompanying such drafts, and written responses thereto shall be placed in the docket no later than the date of promulgation.

(5) In promulgating a rule to which this subsection applies (i) the Administrator shall allow any person to submit written comments, data, or documentary information; (ii) the Administrator shall give interested persons an opportunity for the oral presentation of data, views, or arguments, in addition to an opportunity to make written submissions; (iii) a transcript shall be kept of any oral presentation; and (iv) the Administrator shall keep the record of such proceeding open for thirty days after completion of the proceeding to provide an opportunity for submission of rebuttal and supplementary information.

(6)(A) The promulgated rule shall be accompanied by (i) a statement of basis and purpose like that referred to in paragraph (3) with respect to a proposed rule and (ii) an explanation of the reasons for any major changes in the promulgated rule from the proposed rule.

(B) The promulgated rule shall also be accompanied by a response to each of the significant comments, criticisms, and new data submitted in written or oral presentations during the comment period.

(C) The promulgated rule may not be based (in part or whole) on any information or data which has not been placed in the docket as of the date of such promulgation.

(7)(A) The record for judicial review shall consist exclusively of the material referred to in paragraph (3), clause (i) of paragraph (4)(B), and subparagraphs (A) and (B) of paragraph (6).

(B) Only an objection to a rule or procedure which was raised with reasonable specificity during the period for public comment (including any public hearing) may be raised during judicial review. If the person raising an objection can demonstrate to the Administrator that it was impracticable to raise such objection within such time or if the grounds for such objection arose after the period for public comment (but within the time specified for judicial review) and if such objection is of central relevance to the outcome of the rule, the Administrator shall convene a proceeding for reconsideration of the rule and provide the same procedural rights as would have been afforded had the information been available at the time the rule was proposed. If the Administrator refuses to convene such a proceeding, such person may seek review of such refusal in the United States court of appeals for the appropriate circuit (as provided in subsection (b) of this section). Such reconsideration shall not postpone the effectiveness of the rule. The effectiveness of the rule may be stayed during such reconsideration, however, by the Administrator or the court for a period not to exceed three months.

(8) The sole forum for challenging procedural determinations made by the Administrator under this subsection shall be in the United States court of appeals for the appropriate circuit (as provided in subsection (b) of this section) at the time of the substantive review of the rule. No interlocutory appeals shall be permitted with respect to such procedural determinations. In reviewing alleged procedural errors, the court may invalidate the rule only if the errors were so serious and related to matters of such central relevance to the rule that there is a substantial likelihood that the rule would have been significantly changed if such errors had not been made.

(9) In the case of review of any action of the Administrator to which this subsection applies, the court may reverse any such action found to be—

(A) arbitrary, capricious, an abuse of discretion, or otherwise not in accordance with law;

(B) contrary to constitutional right, power, privilege, or immunity;

(C) in excess of statutory jurisdiction, authority, or limitations, or short of statutory right; or

(D) without observance of procedure required by law, if (i) such failure to observe such procedure is arbitrary or capricious, (ii) the requirement of paragraph (7)(B) has been met, and (iii) the condition of the last sentence of paragraph (8) is met.

(10) Each statutory deadline for promulgation of rules to which this subsection applies which requires promulgation less than six months after date of proposal may be extended to not more than six months after date of proposal by the Administrator upon a determination that such extension is necessary to afford the public, and the agency, adequate opportunity to carry out the purposes of this subsection.

(11) The requirements of this subsection shall take effect with respect to any rule the proposal of which occurs after ninety days after August 7, 1977.

a. (E) OTHER METHODS OF JUDICIAL REVIEW NOT AUTHORIZED

Nothing in this chapter shall be construed to authorize judicial review of regulations or orders of the Administrator under this chapter, except as provided in this section.

b. (F) COSTS

In any judicial proceeding under this section, the court may award costs of litigation (including reasonable attorney and expert witness fees) whenever it determines that such award is appropriate.

c. (G) STAY, INJUNCTION, OR SIMILAR RELIEF IN PROCEEDINGS RELATING TO NONCOMPLIANCE PENALTIES

In any action respecting the promulgation of regulations under section 7420 of this title or the administration or enforcement of section 7420 of this title no court shall grant any stay, injunctive, or similar relief before final judgment by such court in such action.

d. (H) PUBLIC PARTICIPATION