

UNITED STATES COURT OF APPEALS
FOR DISTRICT OF COLUMBIA CIRCUIT

DEC 21 2015

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

RECEIVED

DENBURY ONSHORE, LLC,

Petitioner,

v.

UNITED STATES ENVIRONMENTAL PROTECTION
AGENCY,

Respondent.

UNITED STATES COURT OF APPEALS
FOR DISTRICT OF COLUMBIA CIRCUIT
FILED
DEC 21 2015
CLERK

No. 15-1475

PETITION FOR REVIEW

Pursuant to section 307(b)(1) of the Clean Air Act, 42 U.S.C. § 7607(b)(1), Denbury Onshore, LLC (“Denbury”) hereby petitions this Court for review of the Final Rule entitled “Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units,” issued by the respondent and published in the Federal Register on October 23, 2015 at 80 Fed. Reg. 64662, *et seq.*

Petitioner asks that this Court set aside that portion of the Final Rule which allows an affected electricity generating unit to receive credit towards its emissions standards for the capture and off-site sequestration of its carbon dioxide emissions only if the carbon dioxide is transferred to a facility that complies with 40 C.F.R. part 98, subpart RR. *See* 80 Fed. Reg. 64957 (40 C.F.R. § 60.5860(f)(2)). That provision is challenged as arbitrary and capricious or otherwise not in accordance with law.

Respectfully submitted,

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Dated: December 21, 2015

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CORPORATE DISCLOSURE STATEMENT

Pursuant to Fed. R. App. P. 26.1 and D.C. Circuit Rule 26.1, petitioner Denbury Onshore, LLC (“Denbury”) files the following statement:

Petitioner Denbury is a wholly owned subsidiary of Denbury Resources Inc., a publicly held corporation whose shares are listed on the New York Stock Exchange. Other than Denbury Resources Inc., no publicly-held company owns 10% or more of any of Petitioner’s stock and no publicly-held company holds 10% or more of Denbury Resources, Inc., stock. The stock of Denbury Resources, Inc. is traded publicly on the New York Stock Exchange under the symbol “DNR.”

Denbury is an oil and gas production company. As a part of its oil recovery operations (generally termed “tertiary” or “enhanced” recovery) that are performed in several states, Denbury, with its affiliated companies, produces, purchases, transports, and injects carbon dioxide for the purpose of the recovery of hydrocarbon resources.

Respectfully submitted,

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Counsel for Petitioner Denbury Onshore, LLC

Dated: December 21, 2015

CERTIFICATE OF SERVICE

I hereby certify that on this 21st day of December 2015, one copy of the foregoing Petition for Review and Corporate Disclosure Statement was served by first-class mail, postage prepaid, on each of the following:

The Honorable Gina McCarthy
Administrator
U.S. Environmental Protection Agency
Ariel Rios Building
1200 Pennsylvania Ave., N.W.
Mail Code 1101A
Washington, D.C. 20460

The Honorable Avi Garbow
General Counsel
U.S. Environmental Protection Agency
Ariel Rios Building
c/o Correspondence Control Unit
Office of General Counsel
1200 Pennsylvania Ave., N.W.
Mail Code 2311
Washington, D.C. 20460

The Honorable Loretta E. Lynch
Attorney General of the United States
U.S. Department of Justice
950 Pennsylvania Ave., N.W.
Washington, D.C. 20530-0001

Jon M. Lipshultz
U.S. Department of Justice
Environmental Defense Section
Environment & Natural Resources
Division
601 D Street, N.W.
Washington, D.C. 20004

Eugene A. Sokoloff

Exhibit 1

The attached pages of the Federal Register include the challenged portion of the Final Rule.



FEDERAL REGISTER

Vol. 80 Friday,
No. 205 October 23, 2015
Book 2 of 2 Books
Pages 64661–65120

Part III

Environmental Protection Agency

40 CFR Part 60
Carbon Pollution Emission Guidelines for Existing Stationary Sources:
Electric Utility Generating Units; Final Rule

construction on or before January 8, 2014.

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

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

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

(1) 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);

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

(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 less of its potential electric output, or 219,000 MWh 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;

(d) Stationary combustion turbines not capable of combusting natural gas (*e.g.*, not connected to a natural gas pipeline);

(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.

§ 60.5855 What are the CO₂ emission performance rates for affected EGUs?

(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.

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

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

(1) The owner or operator of an affected EGU (or group of affected EGUs that share a monitored common stack) that is required to meet rate-based or mass-based emission 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).

(3) 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)(3)(i) through (vi) of this section, except as otherwise provided in paragraph (a)(4) of this section.

(i) 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. 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, 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.

(vi) For each continuous monitoring system used to determine the CO₂ mass emissions 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 to part 75 of this chapter.

(4) 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 (a)(3) of this section, determine the hourly CO₂ mass emissions according to paragraphs (a)(4)(i) through (a)(4)(vi) of this section.

(i) Implement the applicable procedures in appendix D to part 75 of this chapter to determine hourly EGU heat input rates (MMBtu/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 CO₂ 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 CO₂ 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.

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

(5) 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).

(i) Determine P_{net}, 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 P_{net} for your affected EGU (or group of affected EGUs that share a monitored common stack) using

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

Where:

P_{net} = 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.

$(Pe)_{CT}$ = 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:

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

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 P_{net} 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 P_{net} 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 P_{net} 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).

(7) In accordance with § 60.13(g), if the exhaust gases from an affected EGU implementing the continuous emissions monitoring provisions in paragraph (a)(2) of this section are emitted to 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.

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), 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.

(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_{net}). 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) 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. The owner or operator of an affected EGU may maintain the records off site and electronically for the remaining year(s).

(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_{net}) 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 CO₂ 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 CO₂ mass emissions (tons) for each unit or stack operating hour in the compliance period;

(iii) The sum of the CO₂ 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_{net}) 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 CO₂ 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 CO₂ 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 CO₂ 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

§ 60.5865 What are my recordkeeping requirements?

(a) 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 plan for each interim step and the interim period. After 2029, States must keep records of all

information relied upon in support of any continued demonstration that the final CO₂ emission performance rates or CO₂ emissions goals are being achieved.

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

(c) If 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 meets the recordkeeping requirement of this section and you are not required to keep records of information that would be in duplicate of paragraph (b) of this section.

(d) You must keep records at a minimum for 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, CO₂ emission performance rate or CO₂ emissions goal. Each record must be in a form suitable and readily available for expeditious review.

§ 60.5870 What are my 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.

(b) You must submit 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 year 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 CO₂ emission performance rate or CO₂ emission goal (as applicable). The report must include the information in paragraphs (b)(1) through (4) of this section.

(1) The report must include the emissions performance achieved by all affected EGUs during the reporting period, consistent with the plan approach according to § 60.5745(a), and identification of whether each affected

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 CO₂ emission performance rate or emission goal during the performance 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) The report must include all other required information, as specified in your State plan according to § 60.5740(a)(5).

(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.