Appendix B:1 Definitions of New Stationary Sources

Subsec. (h). Pub. L. 95-190, §14(a)(5), redesignated subsec. (g), added by Pub. L. 95-95, §108(g), as (h). Former subsec. (h) redesignated (i).

Subsec. (i). Pub. L. 95-190, §14(a)(5), redesignated subsec. (h), added by Pub. L. 95-95, §108(g), as (i). Former subsec. (i) redesignated (j) and amended.

Subsec. (j). Pub. L. 95-190 §14(a)(5), (6), redesignated subsec. (i), added by Pub. L. 95-95, §108(g), as (j) and in subsec. (j) as so redesignated, substituted "will enable such source" for "at such source will enable it".

1974—Subsec. (a)(3). Pub. L. 93-319, §4(a), designated existing provisions as subpar. (A) and added subpar. (B).

Subsec. (c). Pub. L. 93-319, §4(b), designated existing provisions as par. (1) and existing pars. (1), (2), and (3) as subpars. (A), (B), and (C), respectively, of such redesignated par. (1), and added par. (2).

EFFECTIVE DATE OF 1977 AMENDMENT

Amendment by Pub. L. 95-95 effective Aug. 7, 1977, except as otherwise expressly provided, see section 406(d) of Pub. L. 95-95, set out as a note under section 7401 of this title.

PENDING ACTIONS AND PROCEEDINGS

Suits, actions, and other proceedings lawfully commenced by or against the Administrator or any other officer or employee of the United States in his official capacity or in relation to the discharge of his official duties under act July 14, 1955, the Clean Air Act, as in effect immediately prior to the enactment of Pub. L. 95-95 [Aug. 7, 1977], not to abate by reason of the taking effect of Pub. L. 95-95, see section 406(a) of Pub. L. 95-95, set out as an Effective Date of 1977 Amendment note under section 7401 of this title.

MODIFICATION OR RESCISSION OF RULES, REGULATIONS, ORDERS, DETERMINATIONS, CONTRACTS, CERTIFICATIONS, AUTHORIZATIONS, DELEGATIONS, AND OTHER ACTIONS

All rules, regulations, orders, determinations, contracts, certifications, authorizations, delegations, or other actions duly issued, made, or taken by or pursuant to act July 14, 1955, the Clean Air Act, as in effect immediately prior to the date of enactment of Pub. L. 95-95 [Aug. 7, 1977] to continue in full force and effect until modified or rescinded in accordance with act July 14, 1955, as amended by Pub. L. 95-95 [this chapter], see section 406(b) of Pub. L. 95-95, set out as an Effective Date of 1977 Amendment note under section 7401 of this title.

MODIFICATION OR RESCISSION OF IMPLEMENTATION PLANS APPROVED AND IN EFFECT PRIOR TO AUG. 7, 1977

Nothing in the Clean Air Act Amendments of 1977 [Pub. L. 95-95] to affect any requirement of an approved implementation plan under this section or any other provision in effect under this chapter before Aug. 7, 1977, until modified or rescinded in accordance with this chapter as amended by the Clean Air Act Amendments of 1977, see section 406(c) of Pub. L. 95-95, set out as an Effective Date of 1977 Amendment note under section 7401 of this title.

SAVINGS PROVISION

Pub. L. 91-604, §16, Dec. 31, 1970, 84 Stat. 1713, provided that:

"(a)(1) Any implementation plan adopted by any State and submitted to the Secretary of Health, Education, and Welfare, or to the Administrator pursuant to the Clean Air Act [this chapter] prior to enactment of this Act [Dec. 31, 1970] may be approved under section 110 of the Clean Air Act [this section] (as amended by this Act) [Pub. L. 91-604] and shall remain in effect, unless the Administrator determines that such implementation plan, or any portion thereof, is not consistent with applicable requirements of the Clean Air Act [this chapter] (as amended by this Act) and will not provide for the attainment of national primary ambient air quality standards in the time required by such Act. If the Administrator so determines, he shall, within 90 days after promulgation of any national ambient air quality standards pursuant to section 109(a) of the Clean Air Act [section 7409(a) of this title], notify the State and specify in what respects changes are needed to meet the additional requirements of such Act, including requirements to implement national secondary ambient air quality standards. If such changes are not adopted by the State after public hearings and within six months after such notification, the Administrator shall promulgate such changes pursuant to section 110(c) of such Act [subsec. (c) of this section].

"(2) The amendments made by section 4(b) [amending sections 7403 and 7415 of this title] shall not be construed as repealing or modifying the powers of the Administrator with respect to any conference convened under section 108(d) of the Clean Air Act [section 7415 of this title] before the date of enactment of this Act [Dec. 31, 1970].

"(b) Regulations or standards issued under this title II of the Clean Air Act [subchapter II of this chapter] prior to the enactment of this Act [Dec. 31, 1970] shall continue in effect until revised by the Administrator consistent with the purposes of such Act [this chapter]."

FEDERAL ENERGY ADMINISTRATOR

"Federal Energy Administrator", for purposes of this chapter, to mean Administrator of Federal Energy Administration established by Pub. L. 93-275, May 7, 1974, 88 Stat. 97, which is classified to section 761 et seq. of Title 15, Commerce and Trade, but with the term to mean any officer of the United States designated as such by the President until Federal Energy Administrator takes office and after Federal Energy Administration ceases to exist, see section 798 of Title 15, Commerce and Trade.

Federal Energy Administration terminated and functions vested by law in Administrator thereof transferred to Secretary of Energy (unless otherwise specifically provided) by sections 7151(a) and 7293 of this title.

§7411. Standards of performance for new stationary sources

(a) Definitions

For purposes of this section:

(1) The term "standard of performance" means a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction and any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated.

(2) The term "new source" means any stationary source, the construction or modification of which is commenced after the publication of regulations (or, if earlier, proposed regulations) prescribing a standard of performance under this section which will be applicable to such source.

(3) The term "stationary source" means any building, structure, facility, or installation which emits or may emit any air pollutant. Nothing in subchapter II of this chapter relating to nonroad engines shall be construed to apply to stationary internal combustion engines.

(4) The term "modification" means any physical change in, or change in the method of operation of, a stationary source which increases the amount of any air pollutant emit-

Appendix B:2 Regulation of Electric Utilities in Interstate Commerce

employees, by Reorg. Plan No. 26 of 1950, §§1, 2, eff. July 31, 1950, 15 F.R. 4935, 64 Stat. 1280, 1281, set out in the Appendix to Title 5, Customs Service, referred to in this section, was a service under Department of the Treasury, and Coast Guard, also referred to in this section, was generally a service under such Department, but such Plan excepted, from transfer, functions of Coast Guard, and of Commandant thereof, when Coast Guard was operating as a part of the Navy under sections 1 and 3 of Title 14, Coast Guard.

Reorg. Plan No. III of 1940, §3, eff. June 30, 1940, 5 F.R. 2108, 54 Stat. 1232, set out in the Appendix to Title 5, Government Organization and Employees, consolidated Bureau of Fisheries and Bureau of Biological Survey with their respective functions into one agency in Department of the Interior to be known as Fish and Wildlife Service, and provided that functions of the consolidated agency shall be administered under direction and supervision of Secretary of the Interior.

Reorg. Plan No. II of 1930, set out in the Appendix to Title 5, transferred Bureau of Fisheries in Department of Commerce and its functions to Department of the Interior, to be administered under direction and supervision of Secretary of the Interior.

CHAPTER 12—FEDERAL REGULATION AND DEVELOPMENT OF POWER

SUBCHAPTER I—REGULATION OF THE DEVELOPMENT OF WATER POWER AND RESOURCES

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FINDINGS

Pub. L. 113–23, §2, Aug. 9, 2013, 127 Stat. 493, provided that: "Congress finds that—

"(1) the hydropower industry currently employs approximately 300,000 workers across the United States;

"(2) hydropower is the largest source of clean, renewable electricity in the United States;

"(3) as of the date of enactment of this Act [Aug. 9, 2013], hydropower resources, including pumped storage facilities, provide—

"(A) nearly 7 percent of the electricity generated in the United States; and

"(B) approximately 100,000 megawatts of electric capacity in the United States;

"(4) only 3 percent of the 80,000 dams in the United States generate electricity, so there is substantial potential for adding hydropower generation to non-powered dams; and

"(5) according to one study, by utilizing currently untapped resources, the United States could add approximately 60,000 megawatts of new hydropower capacity by 2025, which could create 700,000 new jobs over the next 13 years."

SUBCHAPTER I—REGULATION OF THE DEVELOPMENT OF WATER POWER AND RESOURCES

CODIFICATION

Section 212 of act of Aug. 26, 1935, ch. 687, 49 Stat. 847, provided that sections 1 to 29 of the Federal Water Power Act, as amended (sections 792, 793, 794 to 797, 798 to 818, 819, and 820 to 823 of this title) shall constitute part I of the act. Said section 212 also repealed sections 25 and 30 of the act (sections 819, 791 of this title). It also contained a proviso as follows: "That nothing in that Act, as amended, shall be construed to repeal or amend the provisions of the amendment to the Federal Water Power Act approved March 3, 1921 (41 Stat. 1353 [section 797a of this title]), or the provisions of any other Act relating to national parks and national monuments."

§ 791. Repealed. Aug. 26, 1935, ch. 687, title II, § 212, 49 Stat. 847

Section, act June 10, 1920, ch. 285, §30, 41 Stat. 1077, designated the act as The Federal Water Power Act.

§ 791a. Short title

This chapter may be cited as the "Federal Power Act".

(June 10, 1920, ch. 285, pt. III, § 321, formerly § 320, as added Aug. 26, 1935, ch. 687, title II, § 213, 49 Stat. 863; renumbered Pub. L. 95–617, title II, § 212, Nov. 9, 1978, 92 Stat. 3148.)

CODIFICATION

Section was enacted as part of part III of the Federal Power Act, and not as part of part I of that Act which comprises this subchapter.

SHORT TITLE OF 2013 AMENDMENT

Pub. L. 113–23, §1(a), Aug. 9, 2013, 127 Stat. 493, provided that: "This Act [amending sections 792, 823a, and 2705 of this title and enacting provisions set out as notes preceding section 791 and under section 797 of this title] may be cited as the 'Hydropower Regulatory Efficiency Act of 2013'."

SHORT TITLE OF 1990 AMENDMENT

Pub. L. 101–575, §1, Nov. 15, 1990, 104 Stat. 2834, provided that: "This Act [enacting section 2243 of Title 42, The Public Health and Welfare, amending sections 796 and 824a–3 of this title and sections 2014, 2061, 2201, and 2284 of Title 42, and enacting provisions set out as a note under section 796 of this title] may be cited as the 'Solar, Wind, Waste, and Geothermal Power Production Incentives Act of 1990'."

SHORT TITLE OF 1988 AMENDMENT

Pub. L. 100–473, §1, Oct. 6, 1988, 102 Stat. 2299, provided that: "This Act [amending section 824e of this title and enacting provisions set out as notes under section 824e of this title] may be cited as the 'Regulatory Fairness Act'."

SHORT TITLE OF 1986 AMENDMENT

Pub. L. 99–495, §1(a), Oct. 16, 1986, 100 Stat. 1243, provided that: "This Act [enacting sections 797b and 823b

shall fail or refuse to attend and testify or to answer any lawful inquiry or to produce books, papers, correspondence, memoranda, contracts, agreements, or other records, if in his or its power so to do, in obedience to the subpena of the Commission, shall be guilty of a misdemeanor and, upon conviction, shall be subject to a fine of not more than $1,000 or to imprisonment for a term of not more than one year, or both.

(d) Testimony by deposition

The testimony of any witness may be taken, at the instance of a party, in any proceeding or investigation pending before the Commission, by deposition, at any time after the proceeding is at issue. The Commission may also order testimony to be taken by deposition in any proceeding or investigation pending before it, at any stage of such proceeding or investigation. Such depositions may be taken before any person authorized to administer oaths not being of counsel or attorney to either of the parties, nor interested in the proceeding or investigation. Reasonable notice must first be given in writing by the party or his attorney proposing to take such deposition to the opposite party or his attorney of record, as either may be nearest, which notice shall state the name of the witness and the time and place of the taking of his deposition. Any person may be compelled to appear and depose, and to produce documentary evidence, in the same manner as witnesses may be compelled to appear and testify and produce documentary evidence before the Commission, as hereinbefore provided. Such testimony shall be reduced to writing by the person taking the deposition, or under his direction, and shall, after it has been reduced to writing, be subscribed by the deponent.

(e) Deposition of witness in a foreign country

If a witness whose testimony may be desired to be taken by deposition be in a foreign country, the deposition may be taken before an officer or person designated by the Commission, or agreed upon by the parties by stipulation in writing to be filed with the Commission. All depositions must be promptly filed with the Commission.

(f) Deposition fees

Witnesses whose depositions are taken as authorized in this chapter, and the person or officer taking the same, shall be entitled to the same fees as are paid for like services in the courts of the United States.

(June 10, 1920, ch. 285, pt. III, § 307, as added Aug. 26, 1935, ch. 687, title II, § 213, 49 Stat. 856; amended Pub. L. 91–452, title II, § 221, Oct. 15, 1970, 84 Stat. 929; Pub. L. 109–58, title XII, § 1284(b), Aug. 8, 2005, 119 Stat. 980.)

AMENDMENTS

2005—Subsec. (a). Pub. L. 109–58 inserted ", electric utility, transmitting utility, or other entity" after "person" in two places and inserted ", or in obtaining information about the sale of electric energy at wholesale in interstate commerce and the transmission of electric energy in interstate commerce" before period at end of first sentence.

1970—Subsec. (g). Pub. L. 91–452 struck out subsec. (g) which related to the immunity from prosecution of any individual compelled to testify or produce evidence, documentary or otherwise, after claiming his privilege against self-incrimination.

EFFECTIVE DATE OF 1970 AMENDMENT

Amendment by Pub. L. 91–452 effective on 60th day following Oct. 15, 1970, and not to affect any immunity to which any individual is entitled under this section by reason of any testimony given before 60th day following Oct. 15, 1970, see section 260 of Pub. L. 91–452, set out as an Effective Date; Savings Provision note under section 6001 of Title 18, Crimes and Criminal Procedure.

§ 825g. Hearings; rules of procedure

(a) Hearings under this chapter may be held before the Commission, any member or members thereof or any representative of the Commission designated by it, and appropriate records thereof shall be kept. In any proceeding before it, the Commission, in accordance with such rules and regulations as it may prescribe, may admit as a party any interested State, State commission, municipality, or any representative of interested consumers or security holders, or any competitor of a party to such proceeding, or any other person whose participation in the proceeding may be in the public interest.

(b) All hearings, investigations, and proceedings under this chapter shall be governed by rules of practice and procedure to be adopted by the Commission, and in the conduct thereof the technical rules of evidence need not be applied. No informality in any hearing, investigation, or proceeding or in the manner of taking testimony shall invalidate any order, decision, rule, or regulation issued under the authority of this chapter.

(June 10, 1920, ch. 285, pt. III, § 308, as added Aug. 26, 1935, ch. 687, title II, § 213, 49 Stat. 858.)

§ 825h. Administrative powers of Commission; rules, regulations, and orders

The Commission shall have power to perform any and all acts, and to prescribe, issue, make, amend, and rescind such orders, rules, and regulations as it may find necessary or appropriate to carry out the provisions of this chapter. Among other things, such rules and regulations may define accounting, technical, and trade terms used in this chapter; and may prescribe the form or forms of all statements, declarations, applications, and reports to be filed with the Commission, the information which they shall contain, and the time within which they shall be filed. Unless a different date is specified therein, rules and regulations of the Commission shall be effective thirty days after publication in the manner which the Commission shall prescribe. Orders of the Commission shall be effective on the date and in the manner which the Commission shall prescribe. For the purposes of its rules and regulations, the Commission may classify persons and matters within its jurisdiction and prescribe different requirements for different classes of persons or matters. All rules and regulations of the Commission shall be filed with its secretary and shall be kept open in convenient form for public inspection and examination during reasonable business hours.

(June 10, 1920, ch. 285, pt. III, § 309, as added Aug. 26, 1935, ch. 687, title II, § 213, 49 Stat. 858.)

may be available to the Secretary, including information voluntarily provided in a timely manner by the applicant and others. The Secretary shall also submit, together with the aforementioned written statement, all studies, data, and other factual information available to the Secretary and relevant to the Secretary's decision.

(5) If the Commission finds that the Secretary's final condition would be inconsistent with the purposes of this subchapter, or other applicable law, the Commission may refer the dispute to the Commission's Dispute Resolution Service. The Dispute Resolution Service shall consult with the Secretary and the Commission and issue a non-binding advisory within 90 days. The Secretary may accept the Dispute Resolution Service advisory unless the Secretary finds that the recommendation will not adequately protect the reservation. The Secretary shall submit the advisory and the Secretary's final written determination into the record of the Commission's proceeding.

(b) Alternative prescriptions

(1) Whenever the Secretary of the Interior or the Secretary of Commerce prescribes a fishway under section 811 of this title, the license applicant or any other party to the license proceeding may propose an alternative to such prescription to construct, maintain, or operate a fishway.

(2) Notwithstanding section 811 of this title, the Secretary of the Interior or the Secretary of Commerce, as appropriate, shall accept and prescribe, and the Commission shall require, the proposed alternative referred to in paragraph (1), if the Secretary of the appropriate department determines, based on substantial evidence provided by the license applicant, any other party to the proceeding, or otherwise available to the Secretary, that such alternative—

(A) will be no less protective than the fishway initially prescribed by the Secretary; and

(B) will either, as compared to the fishway initially prescribed by the Secretary—

(i) cost significantly less to implement; or

(ii) result in improved operation of the project works for electricity production.

(3) In making a determination under paragraph (2), the Secretary shall consider evidence provided for the record by any party to a licensing proceeding, or otherwise available to the Secretary, including any evidence provided by the Commission, on the implementation costs or operational impacts for electricity production of a proposed alternative.

(4) The Secretary concerned shall submit into the public record of the Commission proceeding with any prescription under section 811 of this title or alternative prescription it accepts under this section, a written statement explaining the basis for such prescription, and reason for not accepting any alternative prescription under this section. The written statement must demonstrate that the Secretary gave equal consideration to the effects of the prescription adopted and alternatives not accepted on energy supply, distribution, cost, and use; flood control; navigation; water supply; and air quality (in addition to the preservation of other aspects of environmental quality); based on such information as may be available to the Secretary, including information voluntarily provided in a timely manner by the applicant and others. The Secretary shall also submit, together with the aforementioned written statement, all studies, data, and other factual information available to the Secretary and relevant to the Secretary's decision.

(5) If the Commission finds that the Secretary's final prescription would be inconsistent with the purposes of this subchapter, or other applicable law, the Commission may refer the dispute to the Commission's Dispute Resolution Service. The Dispute Resolution Service shall consult with the Secretary and the Commission and issue a non-binding advisory within 90 days. The Secretary may accept the Dispute Resolution Service advisory unless the Secretary finds that the recommendation will not adequately protect the fish resources. The Secretary shall submit the advisory and the Secretary's final written determination into the record of the Commission's proceeding.

(June 10, 1920, ch. 285, pt. I, § 33, as added Pub. L. 109–58, title II, § 241(c), Aug. 8, 2005, 119 Stat. 675.)

SUBCHAPTER II—REGULATION OF ELECTRIC UTILITY COMPANIES ENGAGED IN INTERSTATE COMMERCE

§ 824. Declaration of policy; application of subchapter

(a) Federal regulation of transmission and sale of electric energy

It is declared that the business of transmitting and selling electric energy for ultimate distribution to the public is affected with a public interest, and that Federal regulation of matters relating to generation to the extent provided in this subchapter and subchapter III of this chapter and of that part of such business which consists of the transmission of electric energy in interstate commerce and the sale of such energy at wholesale in interstate commerce is necessary in the public interest, such Federal regulation, however, to extend only to those matters which are not subject to regulation by the States.

(b) Use or sale of electric energy in interstate commerce

(1) The provisions of this subchapter shall apply to the transmission of electric energy in interstate commerce and to the sale of electric energy at wholesale in interstate commerce, but except as provided in paragraph (2) shall not apply to any other sale of electric energy or deprive a State or State commission of its lawful authority now exercised over the exportation of hydroelectric energy which is transmitted across a State line. The Commission shall have jurisdiction over all facilities for such transmission or sale of electric energy, but shall not have jurisdiction, except as specifically provided in this subchapter and subchapter III of this chapter, over facilities used for the generation of electric energy or over facilities used in local distribution or only for the transmission of electric energy in intrastate commerce, or over facilities for the transmission of electric energy consumed wholly by the transmitter.

Appendix B:4 RTO Authority for Transmission Rate-Setting

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Title 18: Conservation of Power and Water Resources

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Subpart J—Credit Practices In Organized Wholesale Electric Markets

§35.45 Applicability.
§35.46 Definitions.
§35.47 Tariff provisions regarding credit practices in organized wholesale electric markets.

AUTHORITY: 16 U.S.C. 791a-825r, 2601-2645; 31 U.S.C. 9701; 42 U.S.C. 7101-7352.

SOURCE: Order 271, 28 FR 10573, Oct. 2, 1963, unless otherwise noted.

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Subpart A—Application

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§35.1 Application; obligation to file rate schedules, tariffs and certain service agreements.

(a) Every public utility shall file with the Commission and post, in conformity with the requirements of this part full and complete rate schedules and tariffs and those service agreements not meeting the requirements of §35.1 (g), clearly and specifically setting forth all rates and charges for any transmission or sale of electric energy subjec to the jurisdiction of this Commission, the classifications, practices, rules and regulations affecting such rates, charges, classifications, services, rules, regulations or practices, as required by section 205(c) of the Federal Power Act (49 Stat. 851; 16 U.S.C. 824d(c)). Where two or more public utilities are parties to the same rate schedule or tariff, each public utility transmitting or selling electric energy subject to the jurisdiction of this Commission shall post and file such rate schedule, or the rate schedule may be filed by one such public utility anc all other parties having an obligation to file may post and file a certificate of concurrence on the form indicated in §131.52 of this chapter: *Provided, however,* In cases where two or more public utilities are required to file rate schedules or certificates of concurrence such public utilities may authorize a designated representative to file upo behalf of all parties if upon written request such parties have been granted Commission authorization therefor.

(b) A rate schedule, tariff, or service agreement applicable to a transmission or sale of electric energy, other than that which proposes to supersede, cancel or otherwise change the provisions of a rate schedule, tariff, or service agreement required to be on file with this Commission, shall be filed as an initial rate in accordance with §35.12.

(d) The utility must submit to the Commission by March 31 of each year, one original and three conformed copies of the financial report furnished to the utility by the Fund's Trustee that shows for the previous calendar year:

(1) Fund assets and liabilities at the beginning of the period;

(2) Activity of the Fund during the period, including amounts received from the utility, a summary amount for purchases of fund investments and a summary amount for sales of fund investments, gains and losses from investment activity, disbursements from the Fund for decommissioning activity and payment of Fund expenses, including taxes; and

(3) Fund assets and liabilities at the end of the period. The report should not include the liability for decommissioning.

(4) Public utilities owning nuclear plants must maintain records of individual purchase and sales transactions until after decommissioning has been completed and any excess jurisdictional amounts have been returned to ratepayers in a manner that the Commission determines. The public utility need not include these records in the financial report that it furnishes to the Commission by March 31 of each year.

(e) The utility must also mail a copy of the financial report provided to the Commission pursuant to paragraph (d) of this section to anyone who requests it.

(f) If an independent public accountant has expressed an opinion on the report or on any portion of the report then that opinion must accompany the report.

[Order 580-A, 62 FR 33348, June 19, 1997, as amended at 69 FR 18803, Apr. 9, 2004; Order 658, 70 FR 34343, June 14, 2005; Order 737, 75 FR 43404, July 26, 2010]

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Subpart F—Procedures and Requirements Regarding Regional Transmission Organizations

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§35.34 Regional Transmission Organizations.

(a) *Purpose.* This section establishes required characteristics and functions for Regional Transmission Organizations for the purpose of promoting efficiency and reliability in the operation and planning of the electric transmission grid and ensuring non-discrimination in the provision of electric transmission services. This section further directs each public utility that owns, operates, or controls facilities used for the transmission of electric energy in interstate commerce to make certain filings with respect to forming and participating in a Regional Transmission Organization.

(b) *Definitions.* (1) *Regional Transmission Organization* means an entity that satisfies the minimum characteristics set forth in paragraph (j) of this section, performs the functions set forth in paragraph (k) of this section, and accommodates the open architecture condition set forth in paragraph (l) of this section.

(2) *Market participant* means:

(i) Any entity that, either directly or through an affiliate, sells or brokers electric energy, or provides ancillary services to the Regional Transmission Organization, unless the Commission finds that the entity does not have economic or commercial interests that would be significantly affected by the Regional Transmission Organization' actions or decisions; and

(ii) Any other entity that the Commission finds has economic or commercial interests that would be significant affected by the Regional Transmission Organization's actions or decisions.

(3) *Affiliate* means the definition given in section 2(a)(11) of the Public Utility Holding Company Act (15 U.S.C 79b(a)(11)).

(4) *Class of market participants* means two or more market participants with common economic or commerci interests.

(c) *General rule.* Except for those public utilities subject to the requirements of paragraph (h) of this section, every public utility that owns, operates or controls facilities used for the transmission of electric energy in interstat commerce as of March 6, 2000 must file with the Commission, no later than October 15, 2000, one of the followin

Costs; see 61 FR 21540, May 10, 1996), must, individually or jointly with other entities, file with the Commission, no later than January 15, 2001:

(1) A statement that it is participating in a transmission entity that has been so approved;

(2) A detailed explanation of the extent to which the transmission entity in which it participates has the characteristics and performs the functions of a Regional Transmission Organization specified in paragraphs (j) an (k) of this section and accommodates the open architecture conditions in paragraph (l) of this section; and

(3) To the extent the transmission entity in which the public utility participates does not meet all the requirements of a Regional Transmission Organization specified in paragraphs (j), (k), and (l) of this section,

(i) A proposal to participate in a Regional Transmission Organization that meets such requirements in accordance with paragraph (d) of this section,

(ii) A proposal to modify the existing transmission entity so that it conforms to the requirements of a Regional Transmission Organization, or

(iii) A filing containing the information specified in paragraph (g) of this section addressing any efforts, obstacles, and plans with respect to conformance with those requirements.

(i) *Entities that become public utilities with transmission facilities.* An entity that is not a public utility that owns operates or controls facilities used for the transmission of electric energy in interstate commerce as of March 6, 2000, but later becomes such a public utility, must file a proposal to participate in a Regional Transmission Organization in accordance with paragraph (d) of this section, or an alternative filing in accordance with paragrapl (g) of this section, by October 15, 2000 or 60 days prior to the date on which the public utility engages in any transmission of electric energy in interstate commerce, whichever comes later. If a proposal to participate in accordance with paragraph (d) of this section is filed, it must propose that operational control of the applicant's transmission system will be transferred to the Regional Transmission Organization within six months of filing the proposal.

(j) *Required characteristics for a Regional Transmission Organization.* A Regional Transmission Organization must satisfy the following characteristics when it commences operation:

(1) *Independence.* The Regional Transmission Organization must be independent of any market participant. The Regional Transmission Organization must include, as part of its demonstration of independence, a demonstration that it meets the following:

(i) The Regional Transmission Organization, its employees, and any non-stakeholder directors must not have financial interests in any market participant.

(ii) The Regional Transmission Organization must have a decision making process that is independent of control by any market participant or class of participants.

(iii) The Regional Transmission Organization must have exclusive and independent authority under section 205 of the Federal Power Act (16 U.S.C. 824d), to propose rates, terms and conditions of transmission service provided over the facilities it operates.

NOTE TO PARAGRAPH (j)(1)(iii): Transmission owners retain authority under section 205 of the Federal Power Act (16 U.S.C 824d) to seek recovery from the Regional Transmission Organization of the revenue requirements associated with the transmission facilities that they own.

(iv)(A) The Regional Transmission Organization must provide:

(*1*) With respect to any Regional Transmission Organization in which market participants have an ownership interest, a compliance audit of the independence of the Regional Transmission Organization's decision making process under paragraph (j)(1)(ii) of this section, to be performed two years after approval of the Regional Transmission Organization, and every three years thereafter, unless otherwise provided by the Commission.

(*2*) With respect to any Regional Transmission Organization in which market participants have a role in the Regional Transmission Organization's decision making process but do not have an ownership interest, a compliance audit of the independence of the Regional Transmission Organization's decision making process und paragraph (j)(1)(ii) of this section, to be performed two years after its approval as a Regional Transmission Organization.

United States
Environmental Protection Agency

Docket ID No. EPA-HQ-OAR-2008-0321

COMMENTS
SUBMITTED ON BEHALF OF
THE PUBLIC UTILITIES COMMISSION OF OHIO

August 4, 2011

A. Reliability Issues

Coal fuels about 85% of the net electric generation in Ohio.[1] The Edison Electric Institute Yearbook (2008 data) shows that the state of Ohio is sixth in electric generation. Implementation of the rule as proposed will have a negative impact on the production of electricity from coal, forcing early decommissioning of coal-fired generating plants in Ohio.

PUCO analysis has predicted that over 150 units within the PJM Interconnection (PJM)[2] could be decommissioned by 2015 given the aggregate of recently proposed and finalized environmental regulations (see Attachment B). Based upon a study by Charles Rivers and Associates, roughly 24 gigawatts (GW) of generation will be retired in PJM.[3] Of the 24 GW, PUCO expects nearly seven GW to be retired within Ohio. Supporting this analysis is the fact that AEP recently stated that it will shut down nearly six GW of capacity due to environmental regulations. Much of this capacity serves Ohioans and/or is located within Ohio. Some of the expected retirements in Ohio will have localized impacts, resulting in reliability concerns in the state and region. As many as four EGUs could be shutdown within a 50 square mile area. If reliability becomes a problem from retirements, then older, smaller, and/or less efficient plants that should retire could become "must run"[4] EGUs to address reliability. This could magnify cost implications.

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[1] Velocity Suite, a PUCO subscription database maintained by Ventyx, 2009.

[2] PJM is a regional transmission organization (RTO) that coordinates the movement of wholesale electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia.

[3] "Summary of MRN-NEEM Results for EIPC BAU Sensitivity 3: Alternative EPA Regulations", Charles Rivers & Associates, April 20, 2011.

[4] PJM's "Must Run" provision is required as part of the PJM Operating Agreement in Schedule 1, Section 6. Reliability "Must Run" Units are compensated under a contract between the owner of the unit and PJM and are approved by FERC. The compensation is generally at cost-plus (higher than the Location Marginal Pricing).

This pending MACT rule, in combination with other EPA rules recently proposed and finalized, could drive the need for significant new infrastructure investment that will eventually be reflected in electric rates. If the MACT rules are implemented as currently proposed, there will be a significant effect on reliability resulting from difficulties in regional transmission organization planning and reliability standards compliance.

The Federal Energy Regulatory Commission (FERC) echoes our concern regarding reliability challenges arising from EPA regulations. At a FERC hearing on September 16, 2010, Chairman Wellinghoff called for an inter-agency taskforce to examine EPA requirements that could affect reliability and the need to keep older generating plants operating.[5] Additionally, Commissioner Moeller expressed the need to understand the implications of shutting down some of the older power plants as the method of complying with EPA regulations. Commissioner Moeller further noted that the challenges of removing generation from the grid and ensuring reliable electricity supplies are largely determined by the location of power plants and stressed the importance of understanding the complicated issue, and noted the pressing need to enter into any remedial situation "with our eyes wide open."[6]

We believe that implementation of MACT as proposed by EPA, will result in an elevated level of uncertainty regarding reliability. As the rule is proposed, it is unclear how many EGUs will need to construct new facilities to meet the rule's stringent requirements. In Ohio, as well as other states that will be affected by the rule, there are many power plants for which

[5] "FERC Chairman Seeks Review of EPA Rules Affecting Electricity Reliability," www.energywashington.com, September 16, 2010.

[6] "FERC's Moeller Warns Plant Location Key in Weighing EPA Regulations," www.energywashington.com, September 24, 2010.

decommissioning, rather than installing additional control equipment, will be a more cost-effective option. When evaluating whether to invest in new installations or decommission, utilities will need to take both unit and site-specific considerations into account. There will likely be significant variation in decision making regarding which practice to employ from utility to utility, causing reliability issues in the future.[7] PUCO is concerned that the proposed rule will lead to an inadequate planning reserve margin. The number of units that will be affected by the proposed rule, combined with the implementation timeframe and the obvious need for capacity replacement leads the PUCO to believe that MACT implementation should be delayed as to avoid a problematic electricity deliverability scenario.

PUCO is not the only entity concerned about the reliability implications associated with recent EPA rulemakings including the MACT. The National Association of Utility Regulatory Commissioners (NARUC) adopted a Resolution at the 2011 Summer Meetings regarding the state concerns with environmental regulations (See Attachment A). In its Resolution, NARUC recognized that some generators that will be impacted by the new EPA rulemakings are located in transmission or generation supply constrained areas and will need time to allow for transmission or new generation studies to determine reliability issue resolutions. Furthermore, the timeline for a retrofit for multimillion dollar projects may take five-plus years, due to utility regulatory commission approval, front end engineering, environmental permitting, detailed engineering, construction and start-up. Also raised by NARUC is the concern that all the

[7] Additionally, PJM requires utilities to provide a 90-day notice of their intention to retire certain generating units. Historically, utilities have provided more than 90 days notice, but this may be difficult under the proposed rule as utilities will have to make compliance decisions in a short timeframe. Such shortened notice periods could cause analysis and evaluation difficulty, potentially undermining reliability throughout the region.

necessary compliance projects would be in competition for the same skilled labor force and resources.

B. Cost-Effectiveness in Relation to Proposed Rule

The proposed rule will assuredly impact wholesale and retail power costs, putting upward pressure on customer (ratepayer) bills. Hasty regulation under MACT will cause early retirement or aggressive, accelerated, and costly plant installations, imposing the necessity of quickly developing new facilities due to the aggressive timeline for implementation in the rule. Further, due to timing issues and attempts to avoid rate shock, there may be requests for deferrals further exacerbating cost concerns and negatively impacting future generations of ratepayers.

The proposed rule, in concert with other anticipated rules, may accelerate the retirement of coal-fired electric generating plants. The cost of premature retirements could have a direct impact on rates, removing some lower-cost locally available power from the market, resulting in a higher-priced marginal unit energy source, and driving the need for additional generating capacity. The current and foreseeable economic environment indicates that Ohio's ratepayers will be hard-pressed to absorb rate shock due to the implementation schedule advanced in the proposed rule. EPA has estimated some costs/benefits associated with the proposed rule. For instance, EPA explains in its Regulatory Impact Analysis (RIA) added costs of regulation at electricity plants. In addition to the concerns outlined above, we are concerned that the cost side of the equation does not take into consideration the non-availability of electric power based on premature plant closures and the potential impacts from such situations on human health and well being.

PUCO understands that the benefits are health based; however, the cost/benefit analysis

Appendix B:6 Comparing Natural Gas Spot Prices, February 2013 and 2014

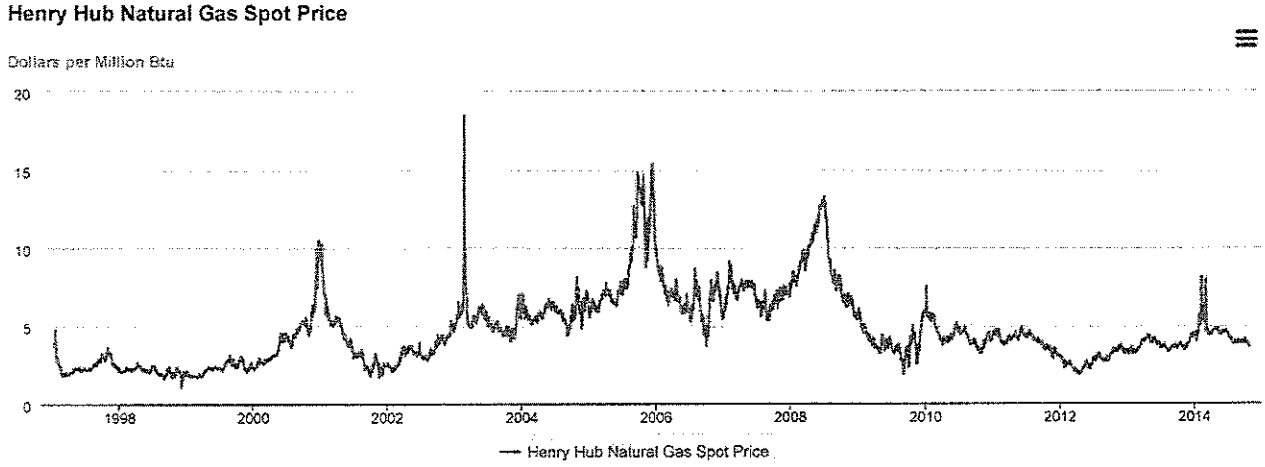
U.S. Energy Information Administration

NATURAL GAS

OVERVIEW | DATA | ANALYSIS & PROJECTIONS GLOSSARY › FAQS ›

View History: ◉ Daily ○ Weekly ○ Monthly ○ Annual Download Data (XLS File)

Henry Hub Natural Gas Spot Price



Source: U.S. Energy Information Administration

Chart Tools

no analysis applied

Henry Hub Natural Gas Spot Price (Dollars per Million Btu)

Week Of	Mon	Tue	Wed	Thu	Fri
1997 Jan- 6 to Jan-10		3.82	3.80	3.61	3.92
1997 Jan-13 to Jan-17	4.00	4.01	4.34	4.71	3.91
1997 Jan-20 to Jan-24	3.26	2.99	3.05	2.96	2.62
1997 Jan-27 to Jan-31	2.98	3.05	2.91	2.86	2.77
1997 Feb- 3 to Feb- 7	2.49	2.59	2.65	2.51	2.39
1997 Feb-10 to Feb-14	2.42	2.34	2.42	2.22	2.12
1997 Feb-17 to Feb-21		1.84	1.95	1.92	1.92
1997 Feb-24 to Feb-28	1.92	1.77	1.81	1.80	1.78
1997 Mar- 3 to Mar- 7	1.80	1.87	1.92	1.82	1.89
1997 Mar-10 to Mar-14	1.95	1.92	1.96	1.98	1.97
1997 Mar-17 to Mar-21	2.01	1.91	1.88	1.88	1.87
1997 Mar-24 to Mar-28	1.80	1.85	1.85	1.84	
1997 Mar-31 to Apr- 4	1.84	1.95	1.85	1.87	1.91
1997 Apr- 7 to Apr-11	1.99	2.01	1.96	1.97	1.98
1997 Apr-14 to Apr-18	2.00	2.00	2.02	2.08	2.10
1997 Apr-21 to Apr-25	2.09	2.10	2.22	2.11	2.16
1997 Apr-28 to May- 2	2.10	2.09	2.16	2.19	2.21
1997 May- 5 to May- 9	2.23	2.25	2.34	2.33	2.30
1997 May-12 to May-16	2.27	2.18	2.22	2.25	2.19
1997 May-19 to May-23	2.25	2.22	2.21	2.22	2.20
1997 May-26 to May-30		2.29	2.34	2.29	2.23
1997 Jun- 2 to Jun- 6	2.20	2.11	2.19	2.18	2.19
1997 Jun- 9 to Jun-13	2.19	2.16	2.16	2.14	2.15
1997 Jun-16 to Jun-20	2.20	2.20	2.22	2.23	2.25
1997 Jun-23 to Jun-27	2.29	2.32	2.32	2.23	2.17
1997 Jun-30 to Jul- 4	2.17	2.16	2.14	2.11	
1997 Jul- 7 to Jul-11	2.13	2.13	2.16	2.15	2.16
1997 Jul-14 to Jul-18	2.18	2.21	2.24	2.29	2.26
1997 Jul-21 to Jul-25	2.17	2.18	2.20	2.24	2.22

2011 Dec-26 to Dec-30		3.09	3.07	3.03	2.98
2012 Jan- 2 to Jan- 6		2.97	2.96	2.91	2.85
2012 Jan- 9 to Jan-13	2.89	2.97	2.81	2.70	2.67
2012 Jan-16 to Jan-20		2.51	2.49	2.36	2.23
2012 Jan-23 to Jan-27	2.39	2.60	2.61	2.68	2.59
2012 Jan-30 to Feb- 3	2.71	2.51	2.32	2.30	2.40
2012 Feb- 6 to Feb-10	2.46	2.60	2.48	2.50	2.51
2012 Feb-13 to Feb-17	2.42	2.48	2.54	2.47	2.67
2012 Feb-20 to Feb-24		2.63	2.60	2.68	2.60
2012 Feb-27 to Mar- 2	2.55	2.44	2.44	2.45	2.38
2012 Mar- 5 to Mar- 9	2.31	2.30	2.24	2.24	2.21
2012 Mar-12 to Mar-16	2.17	2.15	2.13	2.07	2.01
2012 Mar-19 to Mar-23	2.14	2.19	2.21	2.19	2.07
2012 Mar-26 to Mar-30	2.16	2.09	2.05	2.02	2.00
2012 Apr- 2 to Apr- 6	1.88	1.94	2.06	1.98	
2012 Apr- 9 to Apr-13	1.99	1.99	1.91	1.87	1.87
2012 Apr-16 to Apr-20	1.88	1.89	1.87	1.85	1.82
2012 Apr-23 to Apr-27	1.89	1.97	1.99	2.10	2.05
2012 Apr-30 to May- 4	2.10	2.29	2.31	2.29	2.30
2012 May- 7 to May-11	2.30	2.27	2.36	2.36	2.37
2012 May-14 to May-18	2.41	2.38	2.50	2.60	2.56
2012 May-21 to May-25	2.60	2.55	2.60	2.66	2.56
2012 May-28 to Jun- 1		2.50	2.39	2.34	2.24
2012 Jun- 4 to Jun- 8	2.32	2.39	2.41	2.33	2.22
2012 Jun-11 to Jun-15	2.22	2.17	2.18	2.20	2.44
2012 Jun-18 to Jun-22	2.45	2.59	2.60	2.48	2.50
2012 Jun-25 to Jun-29	2.70	2.70	2.87	2.81	2.74
2012 Jul- 2 to Jul- 6	2.73	2.78		2.90	2.94
2012 Jul- 9 to Jul-13	2.79	2.87	2.72	2.83	2.88
2012 Jul-16 to Jul-20	2.92	2.83	2.84	2.99	3.03
2012 Jul-23 to Jul-27	3.05	3.16	3.19	3.13	3.10
2012 Jul-30 to Aug- 3	3.14	3.20	3.20	3.16	2.93
2012 Aug- 6 to Aug-10	2.90	2.99	2.97	2.89	2.84
2012 Aug-13 to Aug-17	2.77	2.79	2.82	2.78	2.70
2012 Aug-20 to Aug-24	2.75	2.80	2.80	2.81	2.81
2012 Aug-27 to Aug-31	2.80	2.71	2.64	2.72	2.72
2012 Sep- 3 to Sep- 7		2.81	2.87	2.85	2.73
2012 Sep-10 to Sep-14	2.66	2.82	2.96	3.01	2.94
2012 Sep-17 to Sep-21	2.83	2.74	2.70	2.76	2.76
2012 Sep-24 to Sep-28	2.82	2.84	2.92	3.01	3.08
2012 Oct- 1 to Oct- 5	3.19	3.21	3.21	3.23	3.26
2012 Oct- 8 to Oct-12	3.18	3.18	3.26	3.28	3.38
2012 Oct-15 to Oct-19	3.35	3.27	3.24	3.28	3.43
2012 Oct-22 to Oct-26	3.49	3.34	3.43	3.39	3.38
2012 Oct-29 to Nov- 2	3.40	3.42	3.50	3.50	3.40
2012 Nov- 5 to Nov- 9	3.34	3.41	3.47	3.45	3.33
2012 Nov-12 to Nov-16	3.40	3.57	3.66	3.63	3.46
2012 Nov-19 to Nov-23	3.63	3.62	3.59		3.59
2012 Nov-26 to Nov-30	3.75	3.77	3.71	3.61	3.46
2012 Dec- 3 to Dec- 7	3.44	3.38	3.41	3.48	3.33
2012 Dec-10 to Dec-14	3.35	3.39	3.33	3.27	3.15
2012 Dec-17 to Dec-21	3.20	3.29	3.25	3.35	3.42
2012 Dec-24 to Dec-28	3.30		3.35	3.31	3.40
2012 Dec-31 to Jan- 4	3.43		3.30	3.19	3.20
2013 Jan- 7 to Jan-11	3.30	3.21	3.14	3.08	3.18
2013 Jan-14 to Jan-18	3.39	3.40	3.43	3.44	3.54
2013 Jan-21 to Jan-25		3.63	3.53	3.56	3.42
2013 Jan-28 to Feb- 1	3.25	3.14	3.24	3.33	3.34
2013 Feb- 4 to Feb- 8	3.27	3.34	3.41	3.39	3.26
2013 Feb-11 to Feb-15	3.20	3.30	3.29	3.30	3.19
2013 Feb-18 to Feb-22		3.23	3.34	3.29	3.27
2013 Feb-25 to Mar- 1	3.42	3.46	3.49	3.48	3.54
2013 Mar- 4 to Mar- 8	3.53	3.63	3.57	3.54	3.57
2013 Mar-11 to Mar-15	3.64	3.71	3.72	3.74	3.89
2013 Mar-18 to Mar-22	3.98	3.96	3.97	4.01	4.01
2013 Mar-25 to Mar-29	4.08	3.99	4.08	4.03	
2013 Apr- 1 to Apr- 5	3.97	4.07	4.00	3.94	3.98
2013 Apr- 8 to Apr-12	4.18	4.08	4.07	4.11	4.21
2013 Apr-15 to Apr-19	4.23	4.19	4.24	4.23	4.38

2013 Apr-22 to Apr-26	4.33	4.27	4.25	4.19	4.16
2013 Apr-29 to May- 3	4.28	4.30	4.31	4.28	3.98
2013 May- 6 to May-10	3.93	3.88	3.86	3.87	3.90
2013 May-13 to May-17	3.87	3.93	4.03	4.01	3.89
2013 May-20 to May-24	4.10	4.13	4.16	4.15	4.15
2013 May-27 to May-31		4.19	4.15	4.12	4.02
2013 Jun- 3 to Jun- 7	4.00	4.00	3.99	3.93	3.79
2013 Jun-10 to Jun-14	3.85	3.77	3.74	3.73	3.76
2013 Jun-17 to Jun-21	3.78	3.90	3.93	3.90	3.85
2013 Jun-24 to Jun-28	3.81	3.77	3.72	3.73	3.57
2013 Jul- 1 to Jul- 5	3.52	3.58	3.54		3.52
2013 Jul- 8 to Jul-12	3.65	3.69	3.69	3.64	3.61
2013 Jul-15 to Jul-19	3.67	3.69	3.67	3.66	3.78
2013 Jul-22 to Jul-26	3.71	3.68	3.70	3.68	3.59
2013 Jul-29 to Aug- 2	3.49	3.48	3.46	3.44	3.39
2013 Aug- 5 to Aug- 9	3.33	3.35	3.32	3.27	3.32
2013 Aug-12 to Aug-16	3.34	3.34	3.36	3.34	3.35
2013 Aug-19 to Aug-23	3.46	3.48	3.51	3.52	3.50
2013 Aug-26 to Aug-30	3.55	3.50	3.54	3.58	3.57
2013 Sep- 2 to Sep- 6		3.64	3.68	3.70	3.55
2013 Sep- 9 to Sep-13	3.62	3.65	3.60	3.57	3.60
2013 Sep-16 to Sep-20	3.64	3.77	3.72	3.73	3.68
2013 Sep-23 to Sep-27	3.66	3.59	3.52	3.49	3.51
2013 Sep-30 to Oct- 4	3.48	3.56	3.63	3.58	3.57
2013 Oct- 7 to Oct-11	3.62	3.72	3.70	3.74	3.74
2013 Oct-14 to Oct-18	3.82	3.83	3.84	3.75	3.72
2013 Oct-21 to Oct-25	3.77	3.70	3.66	3.65	3.69
2013 Oct-28 to Nov- 1	3.61	3.57	3.55	3.57	3.45
2013 Nov- 4 to Nov- 8	3.38	3.37	3.46	3.59	3.54
2013 Nov-11 to Nov-15	3.62	3.69	3.69	3.52	3.56
2013 Nov-18 to Nov-22	3.71	3.63	3.63	3.68	3.78
2013 Nov-25 to Nov-29	3.85	3.87	3.87		3.87
2013 Dec- 2 to Dec- 6	3.85	3.84	3.89	3.97	4.15
2013 Dec- 9 to Dec-13	4.24	4.24	4.24	4.40	4.44
2013 Dec-16 to Dec-20	4.21	4.20	4.25	4.25	4.35
2013 Dec-23 to Dec-27	4.52	4.52		4.40	4.34
2013 Dec-30 to Jan- 3	4.41	4.31		4.32	4.39
2014 Jan- 6 to Jan-10	4.50	4.58	4.36	4.15	3.95
2014 Jan-13 to Jan-17	4.19	4.36	4.45	4.55	4.39
2014 Jan-20 to Jan-24		4.61	4.92	5.64	5.17
2014 Jan-27 to Jan-31	5.66	5.25	5.23	5.27	5.04
2014 Feb- 3 to Feb- 7	5.04	5.78	8.12	6.90	5.92
2014 Feb-10 to Feb-14	8.15	7.75	5.96	5.34	5.54
2014 Feb-17 to Feb-21		5.80	6.00	5.96	6.24
2014 Feb-24 to Feb-28	6.08	5.21	4.81	4.61	4.80
2014 Mar- 3 to Mar- 7	7.09	7.98	6.46	4.89	4.78
2014 Mar-10 to Mar-14	4.67	4.67	4.72	4.41	4.40
2014 Mar-17 to Mar-21	4.57	4.42	4.43	4.39	4.33
2014 Mar-24 to Mar-28	4.42	4.53	4.44	4.39	4.50
2014 Mar-31 to Apr- 4	4.48	4.39	4.39	4.51	4.49
2014 Apr- 7 to Apr-11	4.58	4.57	4.67	4.67	4.67
2014 Apr-14 to Apr-18	4.64	4.69	4.64	4.64	
2014 Apr-21 to Apr-25	4.76	4.76	4.81	4.81	4.83
2014 Apr-28 to May- 2	4.72	4.78	4.79	4.79	4.73
2014 May- 5 to May- 9	4.73	4.80	4.82	4.77	4.59
2014 May-12 to May-16	4.52	4.47	4.47	4.42	4.42
2014 May-19 to May-23	4.54	4.53	4.57	4.57	4.40
2014 May-26 to May-30		4.40	4.56	4.63	4.49
2014 Jun- 2 to Jun- 6	4.49	4.62	4.62	4.66	4.66
2014 Jun- 9 to Jun-13	4.67	4.67	4.51	4.51	4.70
2014 Jun-16 to Jun-20	4.71	4.68	4.68	4.67	4.53
2014 Jun-23 to Jun-27	4.53	4.49	4.58	4.58	4.39
2014 Jun-30 to Jul- 4	4.39	4.47	4.47	4.31	
2014 Jul- 7 to Jul-11	4.31	4.18	4.17	4.15	4.13
2014 Jul-14 to Jul-18	4.13	4.13	4.16	4.04	4.08
2014 Jul-21 to Jul-25	3.87	3.81	3.83	3.83	3.86
2014 Jul-28 to Aug- 1	3.84	3.79	3.78	3.78	3.77
2014 Aug- 4 to Aug- 8	3.87	3.87	3.92	3.99	3.94

2014 Aug-11 to Aug-15	4.00	3.94	3.90	3.85	3.89
2014 Aug-18 to Aug-22	3.78	3.84	3.88	3.88	3.88
2014 Aug-25 to Aug-29	3.94	3.99	4.02	4.06	4.04
2014 Sep- 1 to Sep- 5		4.01	3.94	3.91	3.86
2014 Sep- 8 to Sep-12	3.86	3.93	3.98	3.94	3.82
2014 Sep-15 to Sep-19	3.92	3.85	3.97	3.99	3.99
2014 Sep-22 to Sep-26	3.88	3.90	3.84	3.89	3.89
2014 Sep-29 to Oct- 3	3.89	4.14	4.14	4.00	3.94
2014 Oct- 6 to Oct-10	3.89	3.88	3.88	3.87	3.86
2014 Oct-13 to Oct-17	3.87	3.91	3.81	3.80	3.73
2014 Oct-20 to Oct-24	3.69	3.62	3.69	3.60	

- = No Data Reported; -- = Not Applicable; NA = Not Available; W = Withheld to avoid disclosure of individual company data.

Release Date: 10/22/2014
Next Release Date: 10/29/2014

Referring Pages:

- Natural Gas Futures Prices (NYMEX)

Appendix B:7 Ohio Administrative Code Capability Definition

Chapter 4901:5-5 Electric Utility Forecast Reports

4901:5-5-01 Definitions.

(A) "ATC" means available transfer capability as defined by the regional reliability organization standards.

(B) "Alternative energy resource" has the meaning set forth in division (A)(1) of section 4928.64 of the Revised Code.

(C) "Available system capability" means the installed capability of all generating units on the utility system plus firm purchases.

(D) "Capability" means the net seasonal demonstrated rating of generating equipment, as defined by the regional reliability organization reliability standards.

(E) "Certified territory" means the service area established for an electric supplier under sections 4933.81 to 4933.90 of the Revised Code.

(F) "Demand-side management" means those programs or activities that are designed to modify the magnitude and/or patterns of electricity consumption in a utility's service area by means of equipment installed or actions taken on the customer's premises.

(G) "Electric transmission owner" means the owner of a major utility facility as defined in section 4935.04 of the Revised Code.

(H) "Energy-price relationships" means the calculated or observed effect on peak load, load shape, or energy consumption resulting from changes in the retail price of electricity or other fuels.

(I) "Forecast year," "year of the forecast," or "year zero" means the year in which the forecast is filed.

(J) "Forecast period" means year zero through year ten.

(K) "Integrated operating system" means a group of electric transmission owners or electric utilities who are members of a jointly or commonly operated system as a single entity.

(L) "Integrated resource plan" means that plan or program, established by a person subject to the requirements of this chapter, to furnish electric energy services in a cost-effective and reasonable manner consistent with the provision of adequate and reliable service, which gives appropriate consideration to supply- and demand-side resources and transmission or distribution investments for meeting the person's projected demand and energy requirements.

(M) "Internal load" of a system means the summation of the net output of its generators plus the net of interconnection receipts and deliveries.

(N) "Interruptible load" means load that can be curtailed or reduced at the supplier's discretion or in accordance with a contractual agreement.

(130th General Assembly)
(Substitute Senate Bill Number 310)

AN ACT

To amend sections 3706.25, 4928.01, 4928.20, 4928.53, 4928.64, 4928.65, and 4928.66, to amend, for the purpose of adopting a new section number as indicated in parentheses, section 4928.65 (4928.645), and to enact new section 4928.65 and sections 4928.112, 4928.641, 4928.643, 4928.644, 4928.662, 4928.6610, 4928.6611, 4928.6612, 4928.6613, 4928.6614, 4928.6615, and 4928.6616 of the Revised Code to make changes to the renewable energy, energy efficiency, and peak demand reduction requirements, to prohibit the imposition of a waiting period before enrolling an eligible customer in the percentage of income payment plan, and to create a study committee.

Be it enacted by the General Assembly of the State of Ohio:

SECTION 1. That sections 3706.25, 4928.01, 4928.20, 4928.53, 4928.64, 4928.65, and 4928.66 be amended, section 4928.65 (4928.645) be amended for the purpose of adopting a new section number as indicated in parentheses, and new section 4928.65 and sections 4928.112, 4928.641, 4928.643, 4928.644, 4928.662, 4928.6610, 4928.6611, 4928.6612, 4928.6613, 4928.6614, 4928.6615, and 4928.6616 of the Revised Code be enacted to read as follows:

Sec. 3706.25. As used in sections 3706.25 to 3706.30 of the Revised Code:

(A) "Advanced energy project" means any technologies, products, activities, or management practices or strategies that facilitate the generation or use of electricity or energy and that reduce or support the reduction of energy consumption or support the production of clean, renewable energy for industrial, distribution, commercial, institutional, governmental, research, not-for-profit, or residential energy users including, but not limited to, advanced energy resources and renewable energy resources. "Advanced

utility's certified territory or, in the case of an electric services company, are served by the company and are located within this state. However, nothing in this section precludes a utility or company from providing a greater percentage. ~~The baseline for a utility's or company's compliance with the alternative energy resource requirements of this section shall be the average of such total kilowatt-hours it sold in the preceding three calendar years, except that the commission may reduce a utility's or company's baseline to adjust for new economic growth in the utility's certified territory or, in the case of an electric services company, in the company's service area in this state.~~

~~Of the alternative energy resources implemented by the subject utility or company by 2025 and thereafter:~~

~~(1) Half may be generated from advanced energy resources;~~

(2) ~~At least half~~ The portion required under division (B)(1) of this section shall be generated from renewable energy resources, including one-half per cent from solar energy resources, in accordance with the following benchmarks:

By end of year	Renewable energy resources	Solar energy resources
2009	0.25%	0.004%
2010	0.50%	0.010%
2011	1%	0.030%
2012	1.5%	0.060%
2013	2%	0.090%
2014	2.5%	0.12%
2015	~~3.5~~ 2.5%	~~0.15~~ 0.12%
2016	~~4.5~~ 2.5%	~~0.18~~ 0.12%
2017	~~5.5~~ 3.5%	~~0.22~~ 0.15%
2018	~~6.5~~ 4.5%	~~0.26~~ 0.18%
2019	~~7.5~~ 5.5%	~~0.3~~ 0.22%
2020	~~8.5~~ 6.5%	~~0.34~~ 0.26%
2021	~~9.5~~ 7.5%	~~0.38~~ 0.3%
2022	~~10.5~~ 8.5%	~~0.42~~ 0.34%
2023	~~11.5~~ 9.5%	~~0.46~~ 0.38%
2024 ~~and each calendar year thereafter~~	~~12.5~~ 10.5%	~~0.5~~ 0.42%
2025	11.5%	0.46%
2026 and each calendar year thereafter	12.5%	0.5%.

(3) ~~At least one-half of the~~ The qualifying renewable energy resources

Appendix B:9 Virginia and West Virginia Energy Portfolios

The U.S. Department of Energy and the North Carolina Clean Energy Technology Center are excited to announce that a new, modernized DSIRE is under construction. The new version of DSIRE will offer significant improvements over the current version, including expanded data accessibility and an array of new tools for site users. The new DSIRE site will be available in December 2014. Staff are currently working hard on the new version of DSIRE but are also maintaining the content of the current version of DSIRE. Thank you for your continued support and patience during this transition. We hope you are as excited for December as we are!

DSIRE SOLAR solar policy information

VIRGINIA

Incentives/Policies for Renewables & Efficiency

Printable Version

Voluntary Renewable Energy Portfolio Goal

Like 6

Last DSIRE Review: 03/28/2013

Program Overview:

State:	Virginia
Incentive Type:	Renewables Portfolio Standard
Eligible Renewable/Other Technologies:	Solar Thermal Electric, Photovoltaics, Landfill Gas, Wind, Biomass, Hydroelectric, Geothermal Electric, Energy from Waste, Anaerobic Digestion, Tidal Energy, Wave Energy
Applicable Sectors:	Investor-Owned Utility
Standard:	Goal: 15% of base year (2007) sales by 2025
Technology Minimum:	No
Credit Trading:	Yes
Authority 1:	S.B. 420
Date Enacted:	03/31/2014
Date Effective:	07/01/2014
Authority 2:	Va. Code § 56-585.2
Date Enacted:	4/11/2007 (later amended)
Authority 3:	H.B. 1022
Date Enacted:	04/02/2010
Date Effective:	07/01/2010
Authority 4:	H.B. 2261
Date Enacted:	2/14/2013

Summary:

As part of legislation to re-regulate the state's electricity industry, Virginia enacted a voluntary Renewable Energy Portfolio (RPS) goal in 2007. Legislation passed in 2009 (HB 1994) expanded the goal, encouraging investor-owned utilities to procure a percentage of the power sold in Virginia from eligible renewable energy sources. Legislation passed in 2012 (SB 413) allows investor-owned utilities to meet up to 20% of a renewable energy goal through certificated research and development activity expenses related to renewable energy and alternative energy sources. In addition to allowing participating utilities to recover costs for RPS programs, the Virginia State Corporation Commission (SCC) also offers utilities an increased rate of return (profit) for each "RPS Goal" attained from qualified renewable energy generation facilities approved before January 1, 2013 or offshore wind and nuclear power facilities after July 1, 2013. Power purchase agreements entered into after July 1, 2013 transfers ownership of renewable energy credits (RECs) to participating utility.

RPS Compliance

Each investor-owned electric utility must report to the Commission annually by November 1st on its efforts, if any, to meet the RPS Goals, its overall generation of renewable energy, and any advances in renewable generation technology. Electricity must be generated in Virginia or in the interconnection region of the regional transmission entity.

The RPS targets are defined as percentages of the amount of electricity sold in 2007 (the "base year"), minus the average annual percentage of power supplied from nuclear generators between 2004 and 2006.

The RPS schedule is as follows:

- **RPS Goal I:** 4% of base year sales in 2010
- **RPS Goal II:** Average of 4% of base year sales in 2011 through 2015, and 7% of base year sales in 2016
- **RPS Goal III:** Average of 7% of base year sales in 2017 through 2021, and 12% of base year sales in 2022
- **RPS Goal IV:** Average of 12% of base year sales in 2023 and 2024, and 15% of base year sales in 2025

Investor-owned incumbent electric utilities can gain approval to participate in the voluntary RPS program from the SCC if the utility demonstrates that it has a reasonable expectation of achieving the 12% target in 2022.

Eligible Technologies
Eligible energy resources include solar, wind, geothermal, hydropower*, wave, tidal, and biomass energy.

- Onshore wind and solar power receive a double credit toward RPS goals.
- Offshore wind receives triple credit toward RPS goals.
- Existing renewable energy generators are eligible for RPS compliance.

Renewable Energy Credits (RECs)

Participating utilities may use RECs to meet up to 20% of an annual requirement. All RECs acquired after January 1, 2014 will expire after five years if they are not applied to meet the RPS requirement.

** Hydropower excludes pumped storage, and the amount of wood derived from trees that would be otherwise used by Virginia lumber and pulp manufacturers is capped at 1.5 million tons annually.*

Contact:

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DSIRE SOLAR
solar policy information

WEST VIRGINIA

Incentives/Policies for Renewables & Efficiency

Printable Version

Alternative and Renewable Energy Portfolio Standard

Like 18

Resources
RPS Data
Summary Maps
Summary Tables
Library
What's New?
Search

Last DSIRE Review: 05/19/2014

Program Overview:

State:	West Virginia
Incentive Type:	Renewables Portfolio Standard
Eligible Efficiency Technologies:	CHP/Cogeneration, Certain energy efficiency and demand-side management projects
Eligible Renewable/Other Technologies:	Solar Thermal Electric, Photovoltaics, Landfill Gas, Wind, Biomass, Hydroelectric, Geothermal Electric, Fuel Cells, Municipal Solid Waste, Other Non-Renewable Alternative Energy Resources (see summary for list), Anaerobic Digestion, Small Hydroelectric, Biodiesel, Fuel Cells using Renewable Fuels
Applicable Sectors:	Investor-Owned Utility, Retail Supplier, (serving more than 30,000 customers)
Standard:	25% alternative and renewable energy resources by 2025
Technology Minimum:	At least 90% must come from eligible resources other than natural gas
Credit Trading:	Yes (PJM-GATS)
Credit Transfers Accepted From:	MIRECS into PJM-GATS (Refers to tracking system compatibility only, not RPS eligibility. Please see statutes and regulations for information on facility eligibility)
Credit Transfers Accepted To:	PJM-GATS into MIRECS (Refers to tracking system compatibility only, not RPS eligibility. Please see statutes and regulations for information on facility eligibility)
Authority 1:	W. Va. Code §24-2F-1 et seq.
Date Enacted:	06/02/2009
Date Effective:	07/01/2009 (subsequently amended)
Authority 2:	PSC Order, Case No. 11-0249-E-P
Date Enacted:	11/22/2011

Summary:

In June 2009, West Virginia enacted an *Alternative and Renewable Energy Portfolio Standard* that requires investor-owned utilities (IOUs)* with more than 30,000 residential customers to supply 25% of retail electric sales from eligible alternative and renewable energy resources by 2025.

While this law contains some provisions similar to those found in Renewables Portfolio Standards (RPSs) adopted by other states, West Virginia's standard does not require a minimum contribution from renewable energy resources. The standard can be met using only alternative resources without any renewable resources. As a result, the renewable energy portion of the standard functions as a non-binding goal.

Compliance
The standard sets the following minimum benchmarks for electric utilities based on their annual electricity sales:

- 10% from 2015 to 2019
- 15% from 2020 to 2024
- 25% by January 1st 2025

Each utility submitted a compliance plan in 2010. These initial compliance plans, along with periodic progress reports, will be evaluated by the Public Service Commission (PSC) after January 1, 2015 to verify compliance. The PSC may impose non-compliance assessments if the utility fails to comply with the standard.

Elegible Technologies

To qualify, electricity produced by alternative and renewable resources must be generated or purchased from a facility in West Virginia or in the PJM Service Territory (the regional transmission organization which serves the state). The West Virginia Public Service Commission (PSC) is authorized to certify additional resources as either alternative or renewable. Furthermore, projects that reduce or offset greenhouse gas emissions and certain demand-side or efficiency projects may be certified and counted towards meeting the standard.

Alternative Energy Resources
In West Virginia, "alternative energy resources" include coal technology, coal bed methane, natural gas, fuel produced by a coal gasification or liquification facility, synthetic gas, integrated gasification combined cycle technologies, waste coal, tire-derived fuel, pumped storage hydroelectric projects, and recycled energy (through June 2010).

Renewable Energy Resources
The definition of "renewable energy resources" includes solar-electric, solar thermal energy, wind power, run-of-river hydropower, geothermal energy, fuel cells, and certain biomass energy and biologically-derived fuels. S.B. 350 enacted in April 2010 changed "recycled energy" from classification as an "alternative energy resource" to a renewable energy resource (effective in June 2010).

Energy Credits & Credit Multipliers

An alternative energy credit (AEC) is equal to a megawatt-hour (MWh) of alternative or renewable electricity generation. The PSC uses a public registry and PJM's GATS system to track transactions. Compliance is based on alternative energy credits (AECs), and banking of excess credits is allowed.

Credits will be awarded in the following way:

- One credit for each MWh of electricity generated or purchased from an alternative energy resource facility. It should be noted that utilities may meet no more than 10% of the standard with credits obtained from electricity generated from natural gas.
- Two credits for each MWh of electricity generated or purchased from a renewable energy resource facility
- Three credits for each MWh of electricity generated or purchased from a renewable energy resource facility located on a reclaimed surface mine in West Virginia
- Customer-generators will be awarded one credit for each MWh of electricity generated from an alternative energy resource facility and two credits for each MWh of electricity generated from a renewable energy resource facility.
- The PSC is authorized to award one credit to an electric utility for each ton of carbon dioxide-equivalent reduced or offset by approved projects.
- The PSC is also authorized to award one credit to an electric utility for each MWh of electricity conserved by an approved energy efficiency or demand-side management project, provided that the project savings are verified and certified according to PSC rules (to be determined).

General Order 184.32 states that in order to claim alternative energy credits, customer generators and behind the meter generators (BTMs) must certify their resource with the Public Utility Commission and then file an Alternative or Renewable Meter Generation. Customer generators and BTMs shall own alternative energy credits unless they have contracted by a third party to provide generation, in which case the third party owns the credits.

Customer generators and BTMs with systems above 10 kW must have meters that meet American National Standards Institute (ANSI) C-12 meter standards. Systems below 10 kW are permitted to make generation measurements based upon system inverters or may also have meters that meet ANSI C-12 standards.

** Including electric distribution companies or electric generation suppliers selling to retail customers. Municipal utilities, rural electric cooperatives, and other utilities serving fewer than 30,000 residential customers are specifically excluded from the standard, although the Public Service Commission (PSC) will consider adopting, by administrative rule, alternative and renewable requirements that would apply to these utilities.*

Contact:
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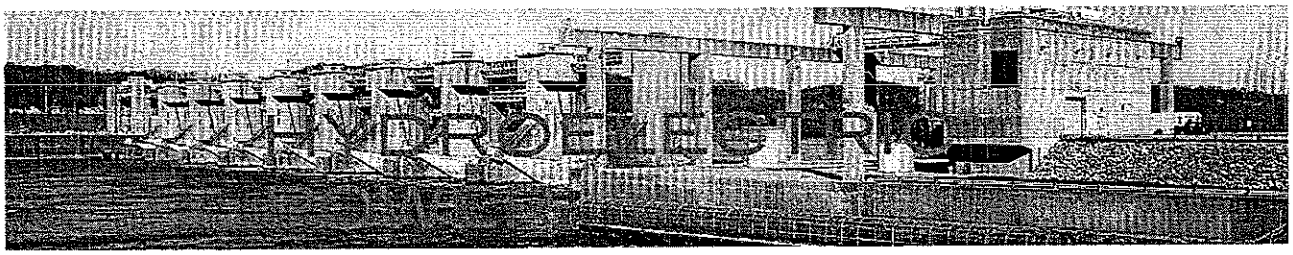
Appendix B:10 AMP Hydroelectric Facilities



American Municipal Power, Inc. (AMP) is actively developing multiple hydroelectric projects in the region, pursuing the largest deployment of clean, renewable run-of-the-river hydroelectric generation in the country.

HYDRO PROJECT FACTS

3
2
6

MW CAPACITY (COMBINED NAMEPLATE RATING)

11 TOTAL TURBINES

FACILITIES

4

Leading the Way in Hydroelectric Power

Hydroelectric power is the most prevalent form of renewable energy used to generate electricity today. Hydroelectric generation is far more dependable than other forms of renewable generation.

The Belleville Hydroelectric Facility

AMP developed and manages a 42 MW run-of-the-river hydroelectric generation facility on behalf of 42 member communities participating in Ohio Municipal Electric Generation Agency Joint Venture 5. The Belleville Hydroelectric Facility is located on the Ohio River at the Belleville (W.Va.) Locks and Dam and went online in April 1999.

Member-operated Hydroelectric

Eight AMP member communities operate locally-owned hydroelectric facilities. These include the cities of Bryan and Hamilton in Ohio, Bedford, Danville and Martinsville in Virginia, Union City in Michigan and New Martinsville in West Virginia.

These facilities have a combined capacity of more than 132 MW.

HYDROELECTRIC PROJECTS

Cannelton Hydro Project

Meldahl Hydro Project

Smithland Hydro Project

Willow Island Hydro Project

HYDROELECTRIC RESOURCES

Hydroelectric Power Editorial

Senator George Voinovich Letter Regarding Meldahl Project

Senator Sherrod Brown Letter Regarding Meldahl Project

GENERATION TYPES

HYDROELECTRIC POWER

FOSSIL FUELS

SOLAR POWER

LANDFILL GAS

WIND POWER

JOINT VENTURES

A new generation of hydroelectric facilities

Currently, AMP is developing five new hydroelectric projects that will add more than 350 MW of new, renewable generation to the region. These run-of-the-river hydroelectric facilities will be installed on existing dams on the Ohio River.

Currently, 79 communities from the states of Ohio, Michigan, Virginia, Kentucky and West Virginia, along with the Central Virginia Electric Cooperative (CVEC), are participating in the hydroelectric projects. Other communities may have the opportunity to participate as additional capacity is added.

A contract exceeding $300 million was signed with York, Penn.-based Voith Hydro to manufacture turbines and generators for the first four of these projects, at the Smithland, Cannelton, Meldahl and Willow Island Locks and Dams.

AMP owns the Meldahl project, through a separate wholly owned limited liability company. AMP is developing the project with the member community of Hamilton, Ohio, which originally procured the development license from the Federal Energy Regulatory Commission (FERC). Hamilton retains the rights for a 51 percent share of the energy output from the facility, with AMP taking the remaining output for the 48 other AMP members participating in the project.

FEDERAL REGISTER

Vol. 79 Wednesday,
No. 117 June 18, 2014

Part II

Environmental Protection Agency

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

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 60

[EPA–HQ–OAR–2013–0602; FRL–9911–86–OAR]

RIN 2060–AR33

Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units

AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed rule.

SUMMARY: In this action, the Environmental Protection Agency (EPA) is proposing emission guidelines for states to follow in developing plans to address greenhouse gas emissions from existing fossil fuel-fired electric generating units. Specifically, the EPA is proposing state-specific rate-based goals for carbon dioxide emissions from the power sector, as well as guidelines for states to follow in developing plans to achieve the state-specific goals. This rule, as proposed, would continue progress already underway to reduce carbon dioxide emissions from existing fossil fuel-fired power plants in the United States.

DATES: *Comments on the proposed rule.* Comments must be received on or before October 16, 2014. *Comments on the information collection request.* Under the Paperwork Reduction Act (PRA), since the Office of Management and Budget (OMB) is required to make a decision concerning the information collection request between 30 and 60 days after June 18, 2014, a comment to the OMB is best assured of having its full effect if the OMB receives it by July 18, 2014.

Public Hearing. Four public hearings will be convened. On July 29, 2014, one public hearing will be held in Atlanta, Georgia, at the Sam Nunn Atlanta Federal Center Main Tower Bridge Conference Area, Conference Room B, 61 Forsyth Street SW., Atlanta, GA 30303, and one will be held in Denver, Colorado, at the EPA's Region 8 Building, 1595 Wynkoop Street, Denver, Colorado 80202. On July 30, 2014, a public hearing will be held in Washington, DC, at the William Jefferson Clinton East Building, Room 1152, 1201 Constitution Avenue NW., Washington, DC 20004. On July 31, 2014, a public hearing will be held in Pittsburgh, Pennsylvania at the William S. Moorhead Federal Building, Room 1310, 1000 Liberty Avenue, Pittsburgh, Pennsylvania 15222. The hearings in Pittsburgh, Pennsylvania, Atlanta, Georgia, and Washington, DC, will convene at 9:00 a.m. and end at 8:00 p.m. (Eastern Standard Time). The hearing in Denver, Colorado, will convene at 9:00 a.m. and end at 8:00 p.m. (Mountain Daylight Time). For all hearings there will be a lunch break from 12:00 p.m. to 1:00 p.m. and a dinner break from 5:00 p.m. to 6:00 p.m. Please contact Ms. Pamela Garrett at 919–541–7966 or at *garrett.pamela@epa.gov* to register to speak at one of the hearings. The last day to pre-register in advance to speak at the hearings will be Friday, July 25, 2014. Additionally, requests to speak will be taken the day of the hearings at the hearing registration desk, although preferences on speaking times may not be able to be fulfilled. If you require the service of a translator or special accommodations such as audio description, please let us know at the time of registration.

The hearings will provide interested parties the opportunity to present data, views or arguments concerning the proposed action. The EPA will make every effort to accommodate all speakers who arrive and register. Because these hearings are being held at U.S. government facilities, individuals planning to attend the hearing should be prepared to show valid picture identification to the security staff in order to gain access to the meeting room. Please note that the REAL ID Act, passed by Congress in 2005, established new requirements for entering federal facilities. These requirements will take effect July 21, 2014. If your driver's license is issued by Alaska, American Samoa, Arizona, Kentucky, Louisiana, Maine, Massachusetts, Minnesota, Montana, New York, Oklahoma, or the state of Washington, you must present an additional form of identification to enter the federal buildings where the public hearings will be held. Acceptable alternative forms of identification include: Federal employee badges, passports, enhanced driver's licenses and military identification cards. We will list any additional acceptable forms of identification at: *http://www2.epa.gov/cleanpowerplan/*. In addition, you will need to obtain a property pass for any personal belongings you bring with you. Upon leaving the building, you will be required to return this property pass to the security desk. No large signs will be allowed in the building, cameras may only be used outside of the building and demonstrations will not be allowed on federal property for security reasons.

The EPA may ask clarifying questions during the oral presentations, but will not respond to the presentations at that time. Written statements and supporting information submitted during the comment period will be considered with the same weight as oral comments and supporting information presented at the public hearing. Commenters should notify Ms. Garrett if they will need specific equipment, or if there are other special needs related to providing comments at the hearings. Verbatim transcripts of the hearings and written statements will be included in the docket for the rulemaking. The EPA will make every effort to follow the schedule as closely as possible on the day of the hearing; however, please plan for the hearings to run either ahead of schedule or behind schedule. Additionally, more information regarding the hearings will be available at: *http://www2.epa.gov/cleanpowerplan/*.

ADDRESSES: *Comments.* Submit your comments, identified by Docket ID No. EPA–HQ–OAR–2013–0602, by one of the following methods:

Federal eRulemaking portal: http://www.regulations.gov. Follow the online instructions for submitting comments.

Email: A-and-R-Docket@epa.gov. Include docket ID No. EPA–HQ–OAR–2013–0602 in the subject line of the message.

Facsimile: (202) 566–9744. Include docket ID No. EPA–HQ–OAR–2013–0602 on the cover page.

Mail: Environmental Protection Agency, EPA Docket Center (EPA/DC), Mail code 28221T, Attn: Docket ID No. EPA–HQ–OAR–2013–0602, 1200 Pennsylvania Ave. NW., Washington, DC 20460. In addition, please mail a copy of your comments on the information collection provisions to the Office of Information and Regulatory Affairs, OMB, Attn: Desk Officer for the EPA, 725 17th St. NW., Washington, DC 20503.

Hand/Courier Delivery: EPA Docket Center, Room 3334, EPA WJC West Building, 1301 Constitution Ave. NW., Washington, DC 20004, Attn: Docket ID No. EPA–HQ–OAR–2013–0602. Such deliveries are accepted only during the Docket Center's normal hours of operation (8:30 a.m. to 4:30 p.m., Monday through Friday, excluding federal holidays), and special arrangements should be made for deliveries of boxed information.

Instructions: All submissions must include the agency name and docket ID number (EPA–HQ–OAR–2013–0602). The EPA's policy is to include all comments received without change, including any personal information provided, in the public docket, available online at *http://www.regulations.gov*, unless the comment includes information claimed to be Confidential

reported 2012 fossil fuel-fired generation.[156]

We note that with the exception of hydropower, the RE generation levels represent total amounts of RE generation, rather than incremental amounts above a particular baseline level. As a result, this RE generation can be supplied by any RE capacity regardless of its date of installation. This approach is therefore focused on quantifying the fulfillment of each state's potential for the deployment of RE as part of BSER using a methodology that does not require discriminating between RE capacity that was installed before or after any given date. Under this approach, states in a given region where a higher proportion of total generation has already been achieved from renewable resources are assumed to have less opportunity for deployment of additional renewable generation as part of the BSER framework informing state goals, in comparison to states in that region where the proportion of total generation achieved from renewable resources to date has been lower. That being said, the assumptions of RE generation used to develop the state goals do not impose any specific RE generation requirements on any state; they are only used to inform the quantification of state goals to which states may respond with whatever emission reduction measures are preferred.

With regard to hydropower, we seek comment regarding whether to include 2012 hydropower generation from each state in that state's "best practices" RE quantified under this approach, and whether and how the EPA should consider year-to-year variability in hydropower generation if such generation is included in the RE targets quantified as part of BSER. Chapter 4 of the GHG Abatement Measures TSD presents state RE targets both with and without the inclusion of each state's 2012 hydropower generation.

2. Cost of CO_2 Emission Reductions From RE Generation

The EPA believes that RE generation at the levels represented in the best practices scenario can be achieved at reasonable costs. According to an EPA analysis based on EIA levelized costs, the cost to reduce emissions through RE ranges from $10 to $40 per metric ton of CO_2.[157] Analysis of RE development in response to state RPS policies also finds historical and projected costs of RPS-driven RE deployment to be modest. One comparative analysis that "synthesize[d] and analyze[d] the results and methodologies of 28 distinct state or utility-level RPS cost impact analyses" projected the median change in retail electricity price to be $0.0004 per kilowatt-hour (a 0.7 percent increase), the median monthly bill impact to be between $0.13 and $0.82, and the median CO_2 reduction cost to be $3 per metric ton.[158] This finding has been confirmed with more recent RPS cost data, including a report that determined 2010–2012 retail electricity price impacts due to state RPS policies to be less than two percent, with only two states experiencing price impacts of greater than three percent.[159] Additionally, the National Renewable Energy Laboratory has projected low incremental costs for a range of scenarios reflecting significant increases in RE penetration, including scenarios that increase RE penetration to a range of 30 to 40 percent of national generation, levels higher than those projected in our best practices scenario.[160]

While RPS requirements will continue to grow over time, the EPA does not expect this anticipated expansion to fall outside the historical norms of deployment or to create unusual pressure for cost increases. Full compliance with current RPS goals through 2035 would require approximately 4 to 4.5 GW of new renewable capacity per year. Average deployment of RPS-supported renewable capacity from 2007 to 2012 exceeded 6 GW per year.[161] In addition, recent improvements in RPS compliance rates indicate to the EPA the reasonableness of current RPS growth trajectories. Weighted average compliance rates among all states have improved in each of the past three reported years (2008–2011) from 92.1 percent to 95.2 percent despite a 40 percent increase in RPS obligations during this period.[162]

We invite comment on this approach to treatment of renewable generating capacity as a basis for the best system of emission reduction adequately demonstrated and for quantification of state goals.

3. Alternative Approach to Quantification of RE Generation

Additionally, the EPA is soliciting comment on an alternative approach to quantification of renewable generation to support the BSER. Unlike the proposed RE scenario described above that relies on a regional application of state RPS commitments, the alternative methodology relies on a state-by-state assessment of RE technical and market potential. The alternative approach is based on two sources of information: A metric representing the degree to which the technical potential of states to develop RE generation has already been realized, and IPM modeling of RE deployment at the state level under a scenario that reflects a reduced cost of building new renewable generating capacity.

The metric measuring realization of RE technical potential in a state compares each state's existing renewable generation by technology type with the technical potential for that technology in that state as assessed by the National Renewable Energy Laboratory (NREL).[163] This comparison yields, for each state and for each RE technology, a proportion of renewable generation technical potential that has been achieved and can be represented as an RE development rate. For example, if

[156] For example, for the state of Washington the proposed approach yields a final RE generation target of 17.7 TWh, representing an increase of 9.5 TWh over Washington's reported 2012 RE generation (excluding hydropower) of 8.2 TWh. By comparison, Washington's 2012 reported fossil fuel-fired generation was 9.4 TWh. (The 2012 reported RE and fossil fuel-fired generation amounts for all states are included in the Goal Computation TSD.) If the limitation described in the text were applied to Washington, the state's incremental quantified RE generation would be limited to 9.4 TWh, with the result that the state's final RE generation target would be 17.6 TWh instead of 17.7 TWh.

[157] This analysis is based upon EIA's AEO 2014 Estimated Levelized Costs of Electricity for New Generation Sources, available at *http://www.eia.gov/forecasts/aeo/electricity_generation.cfm.*

[158] Chen et al., "Weighing the Costs and Benefits of State Renewable Portfolio Standards: A Comparative Analysis of State-Level Policy Impact Projections," Lawrence Berkeley National Laboratory, March 2007, available at *http://emp.lbl.gov/publications/weighing-costs-and-benefits-state-renewables-portfolio-standards-comparative-analysis-s.*

[159] Galen Barbose, "Renewables Portfolio Standards in the United States: A Status Update," Lawrence Berkeley National Lab, November 2013. Also to be published in Heeter et al., "Estimating the Costs and Benefits of Complying with Renewable Portfolio Standards: Reviewing Experience to Date" [review draft title]. UNPUBLISHED. National Renewable Energy Laboratory and Lawrence Berkeley National Laboratory.

[160] NREL, "Renewable Electricity Futures Study", NREL/TP–6A20–52409, 2012, *http://www.nrel.gov/analysis/re_futures/.*

[161] Galen Barbose, "Renewables Portfolio Standards in the United States: A Status Update," Lawrence Berkeley National Laboratory, November 2013.

[162] *http://emp.lbl.gov/rps*, retrieved March 2014. The RPS compliance measure cited is inclusive of credit multipliers and banked RECs utilized for compliance, but excludes alternative compliance payments, borrowed RECs, deferred obligations, and excess compliance. This estimate does not represent official compliance statistics, which vary in methodology by state.

[163] Lopez *et al.*, NREL, "U.S. Renewable Energy Technical Potentials: A GIS-Based Analysis," (July 2012).

Appendix B:12 Force Majeure Requirements

applicable alternative energy portfolio benchmarks and planning requirements have or will be met. Staff shall conduct annual compliance reviews with regard to the benchmarks under the alternative energy portfolio standard.

(1) Beginning in the year 2010, the annual review will include compliance with the most recent applicable renewable- and solar-energy resource benchmark.

(2) Beginning in the year 2025, the annual review will include compliance with the most recent applicable advanced energy resource benchmark.

(3) The annual compliance reviews shall consider any under-compliance an electric utility or electric services company asserts is outside its control, including but not limited to, the following:

(a) Weather-related causes.

(b) Equipment shortages for renewable or advanced energy resources.

(c) Resource shortages for renewable or advanced energy resources.

(B) Any person may file comments regarding the electric utility's or electric services company's alternative energy portfolio status report within thirty days of the filing of such report.

(C) Staff shall review each electric utility's or electric services company's alternative energy portfolio status report and any timely filed comments, and file its findings and recommendations and any proposed modifications thereto.

(D) The commission may schedule a hearing on the alternative energy portfolio status report.

Effective: 12/10/2009
R.C. 119.032 review dates: 09/30/2013
Promulgated Under: 111.15
Statutory Authority: 4901.13 , 4905.04 , 4905.06 , 4928.02 , 4928.64 , 4928.65
Rule Amplifies: 4928.64 , 4928.65

4901:1-40-06 Force majeure.

An electric utility or electric services company may seek a force majeure determination from the commission for all or part of a minimum renewable- or solar-energy benchmark.

(A) A decision on a request for a force majeure determination will be rendered within ninety days of an electric utility or electric services company filing a request for such determination. The process and timeframes for such a determination shall be set by entry of the commission, the legal director, deputy legal director, or attorney examiner.

(1) At the time of requesting such a determination from the commission, an electric utility or electric services company shall demonstrate that it pursued all reasonable compliance options including, but not limited to, renewable energy credit (REC) solicitations, REC banking, and long-term contracts.

(2) The request shall include an assessment of the availability of qualified in-state resources, as well as qualified resources within the territories of PJM and the MISO.

(B) If the commission determines that force majeure conditions exist, it may modify that compliance obligation of the electric utility or electric services company, as it considers appropriate to accommodate the finding.

(1) Such modification does not automatically reduce future-year obligations.

Appendix B:13 Cost of Compliance Provisions

(2) The commission retains the right to increase a future year's compliance obligation by the amount of any under compliance in a previous year that is attributed to a force majeure determination.

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Statutory Authority: 4901.13 , 4905.04 , 4905.06 , 4928.02 , 4928.64
Rule Amplifies: 4928.64

4901:1-40-07 Cost cap.

(A) An electric utility or electric services company may file an application requesting a determination from the commission that its reasonably expected cost of compliance with an advanced energy resource benchmark would exceed its reasonably expected cost of generation to customers by three per cent or more. The process and timeframes for such a determination shall be set by entry of the commission, the legal director, deputy legal director, or attorney examiner.

(1) The burden of proof for substantiating such a claim shall remain with the electric utility or electric services company.

(2) An electric utility or electric services company shall pursue all reasonable compliance options prior to requesting such a determination from the commission.

(3) In the case that the commission makes such a determination, the electric utility or electric services company may not be required to fully comply with that specific benchmark.

(B) An electric utility or electric services company may file an application requesting a determination from the commission that its reasonably expected cost of compliance with a renewable energy resource benchmark, including a solar energy resource benchmark, would exceed its reasonably expected cost of generation to customers by three per cent or more. The process and timeframes for such a determination shall be set by entry of the commission, the legal director, deputy legal director, or attorney examiner.

(1) The burden of proof for substantiating such a claim shall remain with the electric utility or electric services company.

(2) An electric utility or electric services company shall pursue all reasonable compliance options prior to requesting such a determination from the commission.

(3) In the case that the commission makes such a determination, the electric utility or electric services company may not be required to fully comply with that specific benchmark.

(C) Calculations involving a three per cent cost cap shall consist of comparing the total expected cost of generation to customers of an electric utility or electric services company, while satisfying an alternative energy portfolio standard requirement, to the total expected cost of generation to customers of the electric utility or electric services company without satisfying that alternative energy portfolio standard requirement.

(D) Any costs included in a commission-approved unavoidable surcharge for construction or environmental expenditures of generation resources shall be excluded from consideration as a cost of compliance under the terms of the alternative energy portfolio standard and therefore, would not count against the applicable cost cap. Such costs should, however, be included in the calculation of the total expected cost of generation to customers described in paragraph (C) of this rule.

(E) If the commission makes a determination that a three per cent provision is triggered, the electric utility or

(2) The commission retains the right to increase a future year's compliance obligation by the amount of any under compliance in a previous year that is attributed to a force majeure determination.

Effective: 12/10/2009
R.C. 119.032 review dates: 09/30/2013
Promulgated Under: 111.15
Statutory Authority: 4901.13 , 4905.04 , 4905.06 , 4928.02 , 4928.64
Rule Amplifies: 4928.64

4901:1-40-07 Cost cap.

(A) An electric utility or electric services company may file an application requesting a determination from the commission that its reasonably expected cost of compliance with an advanced energy resource benchmark would exceed its reasonably expected cost of generation to customers by three per cent or more. The process and timeframes for such a determination shall be set by entry of the commission, the legal director, deputy legal director, or attorney examiner.

(1) The burden of proof for substantiating such a claim shall remain with the electric utility or electric services company.

(2) An electric utility or electric services company shall pursue all reasonable compliance options prior to requesting such a determination from the commission.

(3) In the case that the commission makes such a determination, the electric utility or electric services company may not be required to fully comply with that specific benchmark.

(B) An electric utility or electric services company may file an application requesting a determination from the commission that its reasonably expected cost of compliance with a renewable energy resource benchmark, including a solar energy resource benchmark, would exceed its reasonably expected cost of generation to customers by three per cent or more. The process and timeframes for such a determination shall be set by entry of the commission, the legal director, deputy legal director, or attorney examiner.

(1) The burden of proof for substantiating such a claim shall remain with the electric utility or electric services company.

(2) An electric utility or electric services company shall pursue all reasonable compliance options prior to requesting such a determination from the commission.

(3) In the case that the commission makes such a determination, the electric utility or electric services company may not be required to fully comply with that specific benchmark.

(C) Calculations involving a three per cent cost cap shall consist of comparing the total expected cost of generation to customers of an electric utility or electric services company, while satisfying an alternative energy portfolio standard requirement, to the total expected cost of generation to customers of the electric utility or electric services company without satisfying that alternative energy portfolio standard requirement.

(D) Any costs included in a commission-approved unavoidable surcharge for construction or environmental expenditures of generation resources shall be excluded from consideration as a cost of compliance under the terms of the alternative energy portfolio standard and therefore, would not count against the applicable cost cap. Such costs should, however, be included in the calculation of the total expected cost of generation to customers described in paragraph (C) of this rule.

(E) If the commission makes a determination that a three per cent provision is triggered, the electric utility or

electric services company shall comply with each benchmark up to the point that the three per cent increment would be reached for each benchmark.

Effective: 12/10/2009
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Promulgated Under: 111.15
Statutory Authority: 4901.13 , 4905.04 , 4905.06 , 4928.02 , 4928.64
Rule Amplifies: 4928.64

4901:1-40-08 Compliance payments.

(A) Any electric utility or electric services company that does not achieve an annual renewable energy resource benchmark, including a solar benchmark, shall remit a compliance payment based on the amount of noncompliance rounded up to the next megawatt hour (MWh), unless the commission has identified the existence of force majeure conditions or the commission has determined that the three per cent cost-cap provision would be exceeded in the event of full compliance.

(1) The required payment for noncompliance with any solar energy resource benchmark shall be calculated by quantifying the level of noncompliance, rounded to the next MWh, and multiplying this figure by the per MWh amount in the table below.

Solar energy resources - compliance payment

Year	Payment per MWh
2009	$450
2010 and 2011	$400
2012 and 2013	$350
2014 and 2015	$300
2016 and 2017	$250
2018 and 2019	$200
2020 and 2021	$150
2022 and 2023	$100
2024 and beyond	$50

(2) The required payment for noncompliance with any renewable energy resource benchmark, excluding solar, shall be calculated by quantifying the level of noncompliance, rounded to the next MWh, and multiplying this figure by an amount determined by the commission.

(a) The per MWh payment for renewable energy resources for the year 2009 is forty-five dollars.

(b) Beginning in the year 2010, the per MWh payment for renewable energy resources will be adjusted annually to reflect the annual change to the consumer price index as defined in section 101.27 of the Revised Code. Such adjustment shall be performed by staff no later than June first of each calendar year. This annual adjustment shall be calculated using the following formula:

Appendix B:15 Double Counting

years of the total annual number of kilowatt-hours of electricity sold to any and all retail electric consumers served by the company in the state, based upon the kilowatt-hour sales in the electric services company's most recent quarterly market-monitoring reports or reporting forms.

(a) If an electric services company has not been continuously supplying Ohio retail electric customers during the preceding three calendar years, the baseline shall be computed as an average of annual sales data for all calendar years during the preceding three years in which the electric services company was serving retail customers.

(b) For an electric services company with no retail electric sales in the state during the preceding three calendar years, its initial baseline shall consist of a reasonable projection of its retail electric sales in the state for a full calendar year. Subsequent baselines shall consist of actual sales data, computed in a manner consistent with paragraph (B)(2)(a) of this rule.

(3) An electric utility or electric services company may file an application requesting a reduced baseline to reflect new economic growth in its service territory or service area. Any such application shall include a justification indicating why timely compliance based on the unadjusted baseline is not feasible, a schedule for achieving compliance based on its unadjusted baseline, quantification of a new change in the rate of economic growth, and a methodology for measuring economic activity, including objective measurement parameters and quantification methodologies.

(C) Beginning in the year 2010, each electric utility and electric services company annually shall file a plan for compliance with future annual advanced- and renewable-energy benchmarks, including solar, utilizing at least a ten-year planning horizon. This plan, to be filed by April fifteenth of each year, shall include at least the following items:

(1) Baseline for the current and future calendar years.

(2) Supply portfolio projection, including both generation fleet and power purchases.

(3) A description of the methodology used by the company to evaluate its compliance options.

(4) A discussion of any perceived impediments to achieving compliance with required benchmarks, as well as suggestions for addressing any such impediments.

Effective: 12/10/2009
R.C. 119.032 review dates: 09/30/2013
Promulgated Under: 111.15
Statutory Authority: 4905.04 , 4905.06 , 4928.02 , 4928.64
Rule Amplifies: 4928.64

4901:1-40-04 Qualified resources.

(A) The following resources or technologies, if they have a placed-in-service date of January 1, 1998, or after, are qualified resources for meeting the renewable energy resource benchmarks:

(1) Solar photovoltaic or solar thermal energy.

(2) Wind energy.

(3) Hydroelectric energy.

(4) Geothermal energy.

(4) Double counting is prohibited.

(5) The RECs must be associated with electricity that was generated no earlier than July 31, 2008.

(E) For a generating facility of seventy-five megawatts or greater that is situated within this state and has committed by December 31, 2009, to modify or retrofit its generating unit or units to enable the facility to generate principally from biomass energy by June 30, 2013, the number of RECs produced by each megawatt-hour of electricity generated principally from biomass energy shall equal the actual percentage of biomass feedstock heat input used to generate such megawatt-hour multiplied by the quotient obtained by dividing the then existing unit dollar amount used to determine a renewable energy compliance payment as provided under division (C)(2)(b) of section 4928.64 of the Revised Code, by the then existing market value of one REC, but such megawatt-hour shall not equal less than one credit.

(F) An entity seeking resource qualification shall file an application for certification of its resources or technologies, upon such forms as may be prescribed by the commission. The application shall include a determination of deliverability to the state in accordance with paragraph (I) of rule 4901:1-40-01 of the Administrative Code.

(1) Any interested person may file a motion to intervene and file comments and objections to any application filed under this rule within twenty days of the date of the filing of the application.

(2) The commission may approve, suspend, or deny an application within sixty days of it being filed. If the commission does not act within sixty days, the application is deemed automatically approved on the sixty-first day after the date filed.

(3) If the commission suspends the application, the applicant shall be notified of the reasons for such suspension and may be directed to furnish additional information. The commission may act to approve or deny a suspended application within ninety days of the date that the application was suspended.

(4) Upon commission approval, the applicant shall receive notification of approval and a numbered certificate where applicable. The commission shall provide this certificate number to the appropriate attribute tracking system.

(5) Representatives of certified facilities must notify the commission within thirty days of any material changes in information previously submitted to the commission during the certification process. Failure to do so may result in revocation of certification status.

(6) Certification of a resource or technology shall not predetermine compliance with annual benchmarks, and does not constitute any commission position regarding cost recovery.

(G) At its discretion, the commission may classify any new technology or additional resource as an advanced- or renewable-energy resource. Any interested person may request a hearing on such classification.

Effective: 12/10/2009
R.C. 119.032 review dates: 09/30/2013
Promulgated Under: 111.15
Statutory Authority: 4901.13 , 4905.04 , 4905.06 , 4928.02 , 4928.64 , 4928.65
Rule Amplifies: 4928.01 , 4928.64 , 4928.65

4901:1-40-05 Annual status reports and compliance reviews.

(A) Unless otherwise ordered by the commission, each electric utility and electric services company shall file by April fifteenth of each year, on such forms as may be published by the commission, an annual alternative energy portfolio status report analyzing all activities undertaken in the previous calendar year to demonstrate how the

US Nuclear Power Plants

General U.S. Nuclear Info

U.S. electricity from nuclear energy in 2013: 19.4 percent, with 789.0 billion kilowatt-hours generated.

- U.S. Nuclear Generating Statistics (1971 - 2013)
- State Fact Sheets

Number of states with operating reactors: 31, including seven states where nuclear makes up the largest percentage of the electricity generated.

- State Electricity Generation Fuel Shares (2013)
- U.S. Electricity Generation Fuel Shares (1949 - 2013)

Nuclear industry capacity factor (2013): 90.9 percent.

- U.S. Capacity Factors by Fuel Type
- U.S. Nuclear Industry Capacity Factors (1971 - 2013)
- U.S. Nuclear Industry Capacity Factors by Quartile (2008 - 2013)

Average refueling outage duration (2013): 41 days.

- U.S. Nuclear Refueling Outage Days (Average, 1990-2013)

Nuclear safety performance:

- U.S. Nuclear Industrial Safety Accident Rate
- Significant Events at U.S. Nuclear Plants
- U.S. Nuclear Industry Scram Trend

U.S. Nuclear Plant Stats

Number of operating reactors: 100, with 35 boiling water reactors (BWRs) and 65 pressurized water reactors (PWRs).

- 14 BWR plants have one reactor; nine have two reactors; one has three reactors
- 13 PWR plants have one reactor; 23 have two reactors; two have three reactors
- U.S. Nuclear Operating Plant Basic Information
- Nuclear Plants in Regulated and Deregulated States

Longest operating period between refueling outages: LaSalle 1 (Illinois); 739 days; February 2006.

Most electricity generated in a year: 11.8 billion kilowatt-hours at South Texas Project 2 in Texas in 2007.

Largest U.S. nuclear plant: Palo Verde (Arizona), three reactors at 1,311; 1,314; and 1,312 megawatts each, for a total of 3,937 megawatts.

Smallest nuclear plant: Fort Calhoun (Nebraska), one reactor at 478 megawatts.

Newest nuclear plant: Watts Bar 1 (Tennessee), operating license issued June 1996.

Oldest operating nuclear plant: Oyster Creek (New Jersey), operating license issued April 1969.

Nuclear plants under construction: Five, including Summer 2 and 3 (South Carolina); Vogtle 3 and 4 (Georgia); Watts Bar 2 (Tennessee).

- New Nuclear Plant Status

Nuclear plant sales: Ownership shares of all or part of 30 nuclear units have been sold since 1999.

- U.S. Nuclear Plant Sales

License renewal: 73 reactors have received 20-year license renewals to operate for a total of 60 years, 30 reactors have applied for or announced intentions to renew their licenses for another 20 years.

- U.S. Nuclear License Renewal Filings
- U.S. Nuclear Plant License Information

Nuclear power uprates: More than 6,900 megawatts of power uprates have been approved by the NRC since 1977. That is the equivalent of adding seven reactors to the electric grid.

- U.S. Nuclear Power Uprates by Plant
- U.S. Nuclear Industry Yearly Power Uprates (1977-2013)
- U.S. Nuclear Expected Power Uprates
- Cumulative Capacity Additions at U.S. Nuclear Facilities (1977 - 2017)

Amount of electricity generated by a 1,000-megawatt reactor at 90 percent capacity factor in one year: 7.9 billion kilowatt-hours—enough to supply electricity for 690,000 households. If generated by other fuel sources, it would require:

- Oil: 13.7 million barrels – 1 barrel yields 576 kWh
- Coal: 3.4 million short tons – 1 ton yields 2,297 kWh
- Natural Gas: 65.8 billion cubic feet – 100 cubic feet yields 12 kWh

(based on average conversion rates from the Energy Information Administration)

First commercial nuclear plant decommissioned: Shippingport in Pennsylvania began operation in December 1957, shut down in 1982.

- Locations of Power Reactor Sites Undergoing Decommissioning
- Decommissioning Status for Shutdown U.S. Power Reactors

U.S. Nuclear Electric Companies

Nuclear plant owners: 68

Nuclear plant operators: 31

- U.S. Nuclear Power Plant Owners, Operators and Holding Companies

Mergers and Acquisitions:

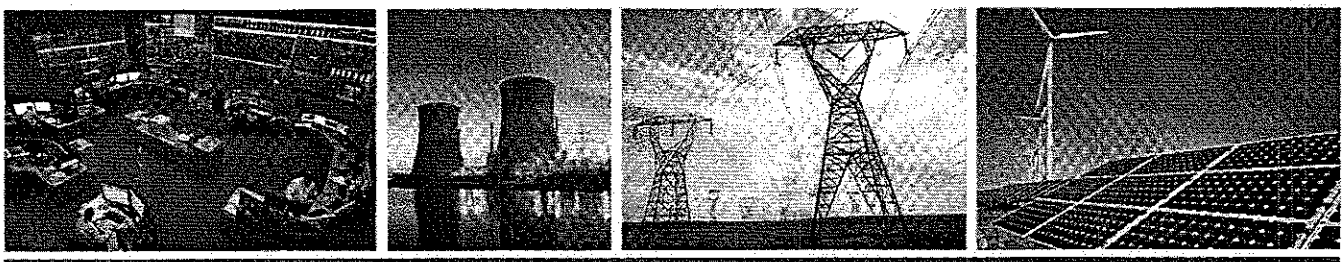
- Duke Energy merged with Progress Energy in July 2012. The merged company is called Duke Energy and includes Progress Energy's ownership of five reactors: Brunswick 1 and 2, Crystal River 3, Robinson and Shearon Harris.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Potential Reliability Impacts of EPA's Proposed Clean Power Plan

Initial Reliability Review
November 2014

RELIABILITY | ACCOUNTABILITY



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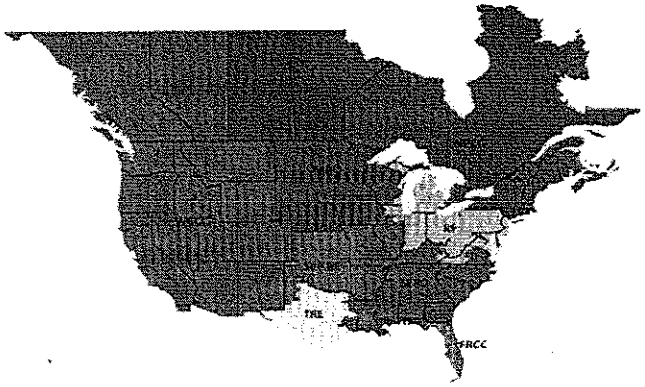
Preface

The North American Electric Reliability Corporation (NERC) has prepared the following assessment in accordance with the Energy Policy Act of 2005, in which the United States Congress directed NERC to conduct periodic assessments of the reliability and adequacy of the bulk power system (BPS) in North America.[1] NERC operates under similar obligations in many Canadian provinces, as well as a portion of Baja California Norte, Mexico.

NERC is an international regulatory authority established to evaluate and improve the reliability of the BPS in North America. NERC develops and enforces Reliability Standards; annually assesses seasonal and long-term (10-year) reliability; monitors the BPS through system awareness; and educates, trains, and certifies industry personnel. NERC is the electric reliability organization (ERO) for North America, subject to oversight by the U.S. Federal Energy Regulatory Commission (FERC) and governmental authorities in Canada.[2]

NERC Regions and Assessment Areas



FRCC	Florida Reliability Coordinating Council
MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	ReliabilityFirst
SERC	SERC Reliability Corporation
SPP-RE	Southwest Power Pool Regional Entity
TRE	Texas Reliability Entity
WECC	Western Electricity Coordinating Council

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[1] H.R. 6 as approved by of the One Hundred Ninth Congress of the United States, the Energy Policy Act of 2005. The NERC Rules of Procedure, Section 800, further detail the Objectives, Scope, Data and Information requirements, and Reliability Assessment Process requiring annual seasonal and long-term reliability assessments.

[2] As of June 18, 2007, FERC granted NERC the legal authority to enforce Reliability Standards with all U.S. users, owners, and operators of the BPS and made compliance with those standards mandatory and enforceable. Equivalent relationships have been sought and for the most part realized in Canada and Mexico. Prior to adoption of §215 in the United States, the provinces of Ontario (2002) and New Brunswick (2004) adopted all Reliability Standards that were approved by the NERC Board as mandatory and enforceable within their respective jurisdictions through market rules. Reliability legislation is in place or NERC has memoranda of understanding with provincial authorities in Ontario, New Brunswick, Nova Scotia, Québec, Manitoba, Saskatchewan, British Columbia, and Alberta, and with the National Energy Board of Canada (NEB). NERC standards are mandatory and enforceable in Ontario and New Brunswick as a matter of provincial law. Manitoba has adopted legislation, and standards are mandatory there. In addition, NERC has been designated as the "electric reliability organization" under Alberta's Transportation Regulation, and certain Reliability Standards have been approved in that jurisdiction; others are pending. NERC standards are now mandatory in British Columbia and Nova Scotia. NERC and the Northeast Power Coordinating Council (NPCC) have been recognized as standards-setting bodies by the Régie de l'énergie of Québec, and Québec has the framework in place for Reliability Standards to become mandatory. NEB has made Reliability Standards mandatory for international power lines. In Mexico, the Comisión Federal de Electricidad (CFE) has signed WECC's reliability management system agreement, which only applies to Baja California Norte.

Executive Summary

The Environmental Protection Agency (EPA), on June 2, 2014, issued its proposed Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, commonly referred to as the proposed Clean Power Plan (CPP), under Section 111(d) of the Clean Air Act, which introduces CO_2 emission limits for existing electric generation facilities. On August 14, 2014, the NERC Board of Trustees directed NERC to develop a series of special reliability assessments to examine the proposed CPP. This report is NERC's initial reliability review of the potential risks to reliability, based on the assumptions contained in the proposed CPP.

NERC maintains a reliability-centered focus on the potential implications of environmental regulations and other shifts in policies that can impact the reliability of the bulk power system (BPS). Reliability assessments conducted while the EPA is finalizing the CPP can inform regulators, state officials, public utility commissioners, utilities, and other impacted stakeholders of potential resource adequacy concerns, impacts to system characteristics (such as essential reliability services (ERSs)), and, to some degree, areas that are more likely to require power-flow-related transmission enhancements to comply with NERC Reliability Standards. The goals of this review are listed in more detail below:

- Provide an evaluation and comparison of the assumptions supporting the CO_2 reduction objectives in the proposed CPP against other reported projections available within NERC assessment reports.
- Provide insight into planned generation retirements, load growth, renewable resource development, and energy efficiency measures that might impact CO_2 emissions and the EPA's target-driven assumptions.
- Provide insight into the potential reliability consequences of either the target-driven emission assumptions or the NERC projection-based assumptions and, in particular, the potential reliability implications if the EPA assumptions cannot be realized.
- Identify potential reliability impacts resulting from the expected resource mix changes, such as coal resource displacement or retirements, the impacts on regional planning reserve margins, the shifts in resource mix and ERS characteristics, the increase in variable resources, the concentration of resources by fuel source (especially natural gas), transmission and large power transfers, and other reliability characteristics, including regional differences.
- Support the electric power industry and NERC stakeholders by providing an independent assessment of reliability while serving as a platform to inform policy discussions on BPS reliability and emerging issues.

This report and its findings are *not* intended to: (1) advocate a policy position in regard to the environmental objectives of the proposed CPP; (2) promote any specific compliance approach; (3) advocate any policy position for a utility, generation facility owner, or other organization to adopt as part of compliance, reliability, or planning responsibilities; (4) support the policy goals of any particular stakeholder or interests of any particular organization; or (5) represent a final and conclusive reliability assessment.

The objective of this review is to identify the reliability implications and potential consequences from the implementation of the proposed CPP and its underlying assumptions. The preliminary review of the proposed rule, assumptions, and transition identified that detailed and thorough analysis will be required to demonstrate that the proposed rule and assumptions are feasible and can be resolved consistent with the requirements of BPS reliability. This assessment provides the foundation for the range of reliability analyses and evaluations that are required by the ERO, RTOs, utilities, and federal and state policy makers to understand the extent of the potential impact. Together, industry stakeholders and regulators will need to develop an approach that accommodates the time required for infrastructure deployments, market enhancements, and reliability needs if the environmental objectives of the proposed rule are to be achieved.

Herein, NERC examines the assumptions made in the EPA's four Building Blocks:[3]

Building Block 1: Heat rate improvements
Building Block 2: Dispatch changes among affected electric generating units (EGUs)
Building Block 3: Using an expanded amount of less-carbon-intensive generating capacity

[3] Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units.

Building Block 4: Demand-side energy efficiency

NERC identified the following factors as requiring additional reliability consideration:

Implementation of the CPP reduces fossil-fired generation: The proposed CPP aims to cut CO_2 emissions from existing power plants to 30 percent below 2005 levels by 2030. Under the EPA proposal, substantial CO_2 reductions are required under the State Implementation Plans (SIPs) as early as 2020. According to the EPA's *Regulatory Impact Assessment*, generation capacity would be reduced by between 108 and 134 GW by 2020 (depending on state or regional implementations of Option 1 or 2).[4] The number of estimated retirements identified in the EPA's proposed rule may be conservative if the assumptions prove to be unachievable. Developing suitable replacement generation resources to maintain adequate reserve margin levels may represent a significant reliability challenge, given the constrained time period for implementation.

Assumed heat rate improvements for existing generation may be difficult to achieve: NERC is concerned that the assumed improvements may not be realized across the entire generation fleet since many plant efficiencies have already been realized and economic heat rate improvements have been achieved. Multiple incentives are in place to operate units at peak efficiency, and periodic turbine overhauls are already a best practice. Site-specific engineering analyses would be required to determine any remaining opportunities for economic heat rate improvement measures.

Greater reliance on variable resources and gas-fired generation is expected: The CPP will accelerate the ongoing shift toward greater use of natural-gas-fired generation and variable energy resources (VERs) (renewable generation). Increased dependence on renewable energy generation will require additional transmission to access areas that have higher-grade wind and solar resources (generally located in remote areas). Increased natural gas use will require pipeline expansion to maintain a reliable source of fuel, particularly during the peak winter heating season. Pipeline constraints and growing gas and electric interdependency challenges impede the electric industry's ability to obtain needed natural gas services, especially during high-use horizons.

Rapid expansion of energy efficiency displaces electricity demand growth through 2030: In its rate calculation for best practices by state, the EPA assumes up to a 1.5 percent annual retail goal for incremental growth in efficiency savings. The EPA assumes that the states and industry would rapidly expand energy efficiency savings programs from 22 TWh/year in 2012, to 108 TWh/year in 2020, and reach 380 TWh/year by 2029. With such aggressive energy efficiency expansion, the EPA assumes that energy efficiency will grow faster than electricity demand, with total electricity demand shrinking after 2020. The implications of this assumption are complex. If the EPA-assumed energy efficiency growth rates cannot be attained, additional carbon reduction measures would be required, primarily through reduced fossil-fired generation.

Essential Reliability Services may be strained by the proposed CPP: The anticipated changes in the resource mix and new dispatching protocols will require comprehensive reliability assessments to identify changes in power flows and ERSs. ERSs are the key services and characteristics that comprise the following basic reliability services needed to maintain BPS reliability: (1) load and resource balance; (2) voltage support; and (3) frequency support. New reliability challenges may arise with the integration of generation resources that have different ERS characteristics than the units that are projected to retire. The changing resource mix introduces changes to operations and expected behaviors of the system; therefore, more transmission and new operating procedures may be needed to maintain reliability.

More time for CPP implementation may be needed to accommodate reliability enhancements: State and regional plans must be approved by the EPA, which is anticipated to require up to one year, leaving as little as six months to two years to implement the approved plan. Areas that experience a large shift in their resource mix are expected to require transmission enhancements to maintain reliability. Constructing the resource additions, as well as the expected transmission enhancements, may represent a significant reliability challenge given the constrained time period for implementation. While

[4] Regional implementation of Option 2 assumes 108 GW of retirements (includes CC, Coal, CT, Nuclear, O/G, and IGCC) by 2020. State implementation of Option 1 assumes 134 GW of retirements (includes CC, Coal, CT, Nuclear, O/G, and IGCC) by 2020. For additional information, see: Regulatory Impacts Analysis for the Proposed Carbon Pollution Guidelines for Existing Power Plants and Emission Standards for Modified and Reconstructed Power Plants (June 2014) and supporting IPM Model documentation and data.

the EPA provides flexibility for meeting compliance requirements within the proposed time frame, there appears to be less flexibility in providing reliability assurance beyond the compliance period.

A summary of NERC's initial reliability review recommendations is provided below:

General Recommendations

1. **NERC should continue to assess the reliability implications of the proposed CPP** and provide independent evaluations to stakeholders and policy makers.
2. **Coordinated regional and multi-regional industry planning and analysis groups should immediately begin detailed system evaluations to identify areas of concern** and work in partnership with policy makers to ensure there is clear understanding of the complex interdependencies resulting from the rule's implementation.
3. **If the environmental goals are to be achieved, policy makers and the EPA should consider a more timely approach** that addresses BPS reliability concerns and infrastructure deployments.

Recommendations to Address Direct Impacts to Resource Adequacy and Electric Infrastructure

Fossil-Fired Retirements and Accelerated Declines in Reserve Margins

The Regions, ISO/RTOs, and states should perform further analyses to examine potential resource adequacy concerns.

Transmission Planning and Timing Constraints

The EPA and states, along with industry, should consider the time required to integrate potential transmission enhancements and additions necessary to address impacts to reliability from the proposed CPP. The EPA and policy makers should recognize the complexity of the reliability challenges posed by the rule and ensure the rule provides sufficient time for the industry to take the steps needed to significantly change the country's resource mix and operations without negatively affecting BPS reliability.

Regional Reliability Assessment of the Proposed CPP

Other ISO/RTOs, states, and Regions should prepare for the potential impacts to grid reliability, taking into consideration the time required to plan and build transmission infrastructure.

Reliability Assurance

The EPA, FERC, the DOE, and state utility regulators should employ the array of tools and their regulatory authority to develop a reliability assurance mechanism, such as a "reliability back-stop." These mechanisms include timing adjustments and granting extensions where there is a demonstrated reliability need.

Recommendations to Address Impacts Resulting from the Changing Resource Mix

Coal Retirements and the Increased Reliance on Natural Gas for Electric Power

Further coordinated planning between the electric and gas sectors will be needed to ensure a strong and integrated system of fuel delivery and generation adequacy. Coordinated planning processes should include considerations for pipeline expansion to meet the increased reliance on natural gas for electric generation, especially during extreme weather events (e.g., polar vortex).

The Changing Resource Mix and Maintaining Essential Reliability Services

ISO/RTOs, utilities, and Regions (with NERC oversight) should analyze the impacts to ERSs in order to maintain reliability. Additionally, system operators and ISO/RTOs need to develop appropriate processes, tools, and operating practices to adequately address operational changes on the system.

NERC should perform grid-level performance expectations developed from a technology-neutral perspective to ensure ERS targets are met.

The development of technologies (such as electricity storage) help support the reliability objectives of the BPS, and these technologies should be expedited to support the additional variability and uncertainty on the BPS.

Increased Penetration of Distributed Energy Resources (DERs)

ISO/RTOs and system planners and operators should consider the increasing penetration of DERs and potential reliability impacts due to the limited visibility and controllability of these resources.

Plan for NERC Reliability Assessments

After the proposed CPP is finalized, specific transmission and resource adequacy assessments—including resulting reliability impacts—will be essential for supporting the development of SIPs that are aligned with system reliability needs. NERC's plan for reviewing and assessing the reliability impacts of the EPA proposal is included in Figure 1. This review includes a preliminary review of the assumptions and potential reliability impacts resulting from the implementation of the EPA's proposed CPP. As the EPA is scheduled to finalize its rule by June 2015, NERC will develop a specific reliability assessment in early 2015 that will focus on evaluating generation and transmission adequacy and reliability impacts. After the EPA rule is finalized, the states, either individually or in multi-state groups, are required to develop their SIPs by 2016 and 2018, respectively. NERC plans to provide a more specific and comprehensive reliability assessment before SIPs are submitted to the EPA. Additionally, a Phase III approach is tentatively planned for December 2016, which will examine finalized SIPs.

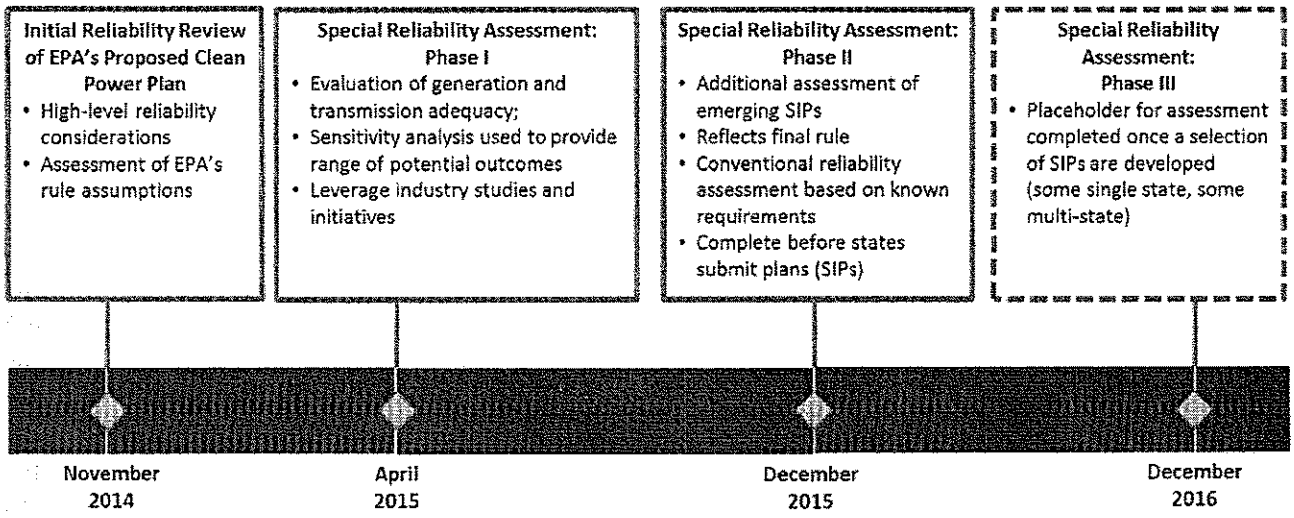

Figure 1. NERC's Assessment Actions and Schedule Timeline

Summary of the Proposed Clean Power Plan

The proposed CPP aims to cut CO_2 emission from existing power plants to 30 percent below 2005 levels by 2030. Substantial CO_2 reductions are required under State Implementation Plans. Under the EPA proposal, CO_2 reductions are required as early as 2020. According to the EPA's reliability assessment included in the proposed rule, these existing generation rules would result in between 108 and 134 GW of generation retirements by 2020 (depending on state or regional implementations of Option 1 or 2).[5]

The CPP proposal would apply to fossil-fired generating units that meet four combined qualification criteria: (1) units that commenced construction prior to January 8, 2014;[6] (2) units with design heat input of more than 250 MMBtu/hour (approximately a 25 MW unit); (3) units that supply over one-third of their potential output to the power grid; and (4) units that supply more than 219,000 MWh/year on a three-year rolling average to the power grid.[7] Given these criteria, the EPA estimates that approximately 3,000 U.S. fossil-fired electric generation units representing over 700,000 MW of existing nameplate generating capacity will be subject to the rule limitations.[8] NERC estimates that this magnitude represents approximately 65 percent of the total existing nameplate capacity in the United States.

The EPA-proposed draft regulations would, for the first time, limit CO_2 from existing power plants, thus addressing risks to health and the economy posed by climate change. These proposed regulations are intended to provide implementation flexibility and maintain an affordable, reliable energy system while cutting CO_2 and protecting public health and the environment.[9]

The EPA regulations propose implementation through a state-federal partnership under which states identify plans to meet the emission reduction goals. The EPA provides guidelines for states to develop implementation plans to meet state-specific CO_2 reduction goals and provides states the flexibility to design requirements suited to their unique situations. These plans may include generation mix changes using diverse fuels, energy efficiency, and demand-side management, and they allow states to work individually or to develop multi-state plans. The primary driver for realizing the EPA's 111(d) objectives is that SIPs need to produce significant CO_2 reductions starting as early as 2020.

As currently proposed, states have a flexible timeline for submitting plans to the EPA. Within one year of finalizing the rule—expected in June 2015—state environmental agencies must submit implementation plans to the EPA for approval. Submitted state-specific plans, due in June 2016, must outline requirements and enforceable limitations for affected generating units to meet the rule's average CO_2 emission rate goal for each state within two compliance periods: (1) an initial 10-year average interim emission rate limit for the period 2020–2029, and (2) a final annual emission rate limit starting in 2030.

The EPA provides states with an option to convert CO_2 emission rate limitation into an annual mass-based limitation. It is likely that most states will pursue this option due to the challenges state permitting agencies have in developing unit-specific emission rate limitations. The simpler mass-based CO_2 emission cap program also negates the need for state legislative action to authorize agencies to limit plant output and enact an enforceable program for compliance with average emission rates. The EPA's proposed Clean Power Plan timeline is outlined in Figure 2.

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[5] State implementation of Option 1 assumes 134 GW of retirements (includes CC, Coal, CT, Nuclear, O/G, and IGCC) by 2020. For additional information, see: Regulatory Impacts Analysis for the Proposed Carbon Pollution Guidelines for Existing Power Plants and Emission Standards for Modified and Reconstructed Power Plants (June 2014) and supporting IPM Model documentation and data. Regional implementation of Option 2 assumes 108 GW of retirements (includes CC, Coal, CT, Nuclear, O/G, and IGCC) by 2020.

[6] All sources starting construction after January 8, 2014, would be subject to new source performance standards and exempt from the EPA Clean Power Plan requirements.

[7] 79 FR 34854 https://www.federalregister.gov/articles/2014/06/18/2014-13726/carbon-pollution-emission-guidelines-for-existing-stationary-sources-electric-utility-generating page 34854.

[8] EPA CPP TSD – 2012 Unit-Level Data Using EGrid – Methodology, June 2014. Generation, Emissions, Capacity data used in EPA's State Goal Computation TSD.

[9] EPA Fact Sheet: Clean Power Plan – Why we Need A Cleaner, More Efficient Power Sector *"The proposed Clean Power Plan will cut hundreds of millions of tons of carbon pollution and hundreds of thousands of tons of harmful particle pollution, sulfur dioxide and nitrogen oxides. Together these reductions will provide important health protections to the most vulnerable, such as children and older Americans."* http://www2.epa.gov/sites/production/files/2014-05/documents/20140602fs-benefits.pdf.

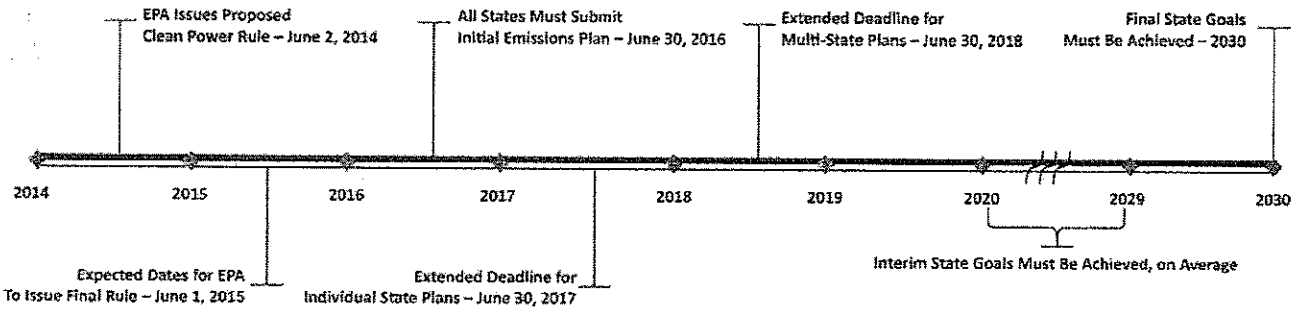


Figure 2. EPA Proposed Clean Power Plan Timeline

The EPA would have one year to review and approve implementation plans for each state by June 2017. Under this schedule, impacted generating units would have two and a half years to develop respective compliance strategies and potentially permit, finance, and build needed replacement capacity and transmission. In its current form, this implementation schedule would be a challenge for states to implement and for affected sources to comply with, especially given the expected legal challenges to both the EPA and state rules. In recognition of these challenges, the EPA would provide states with a one-year extension to June 2017 to submit a SIP if justification is provided, and a two-year extension (June 2018) for states that elect to develop multi-state (regional) programs (e.g., Regional Greenhouse Gas Initiative (RGGI)). While the EPA extensions apply to state plan submissions, the January 1, 2020, program start date for affected sources would not be extended under the proposed CPP. Therefore, the impacted fossil-fired units may be left with as little as six months to develop and implement compliance plans. Considering the number and variety of outcomes for each of the proposed scenarios, the states and industry should initiate planning immediately upon finalization of the CPP.

EPA's Proposed Clean Power Plan: Options

The EPA is proposing a Best System of Emission Reduction (BSER) goal, referred to as Option 1, and is taking comment on a second approach, referred to as Option 2.

Option 1: Involves higher deployment of emission reduction but allows a longer time frame (2030).

Option 2: Has a lower deployment of emission reductions over a shorter time frame (2025) by each state. Proposed guidelines allow states to collaborate and demonstrate emission performance on a multi-state basis, in recognition that electricity is transmitted across state lines.

The proposed Clean Power Plan, which is based on EPA analysis of historical data about emissions and the power sector, is intended to create a consistent national formula for reductions that reflects their Building Block assumptions. The formula applies the four Building Blocks to each state's specific information, yielding a carbon intensity rate for each state.[10] There is a wide range of potential proposals, including individual state and multi-state groupings, each with different implementation schedules. The range of potential submitted SIPs and changes to the proposed timeline create significant uncertainties for industry and resource planners.

Clean Power Plan Building Blocks

According to the proposed plan, this can be achieved through the development of state-specific emission rates to limit CO_2 by applying four different BSER Building Blocks.[11] Each Building Block represents a different approach for achieving the proposed targets. According to the EPA, the proposed plan considers impacts to system reliability and electricity prices. The BSER is not intended to impact resource planning and does not dictate retirements, additions, or operating practices for individual units. Instead, it would provide state emission rate limits that would shape the future resource mix through state and market processes in subsequent years as SIPs and multi-state plans are developed and implemented.

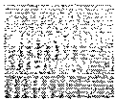
[10] EPA Fact Sheet: Clean Power Plan - National Framework for States.

[11] EPA Clean Air Act: Section 111(d) authorizes EPA to apply "best system of emission reduction" to this section's affected sources.

The EPA's Proposed Clean Power Plan: Four Building Blocks

Make fossil fuel power plants more efficient by implementing a 6 percent (on average) unit heat rate improvement for all affected coal-fired units. The EPA suggests that some plants could further improve process efficiency by 4 percent through the adoption of best operational practices, and an additional 2 percent through capital upgrade investments.

Use low-emitting power sources more by redispatching existing natural gas combined-cycle (NGCC) units before the coal and older oil-gas steam units. EPA draft rate limitations include CO_2 reduction assumptions from the ongoing increases in the use of NGCC capacity (with up to a 70 percent capacity factor). This additional NGCC capacity (440 TWh/year) displaces coal (376 TWh/year) and oil-gas steam generation (64 TWh/year) by 2020, compared to 2012 levels.



Use more zero- and low-emitting power sources through building capacity by adding both non-hydro renewable generation and five planned nuclear units. EPA calculations assume qualifying non-hydro renewable generation can grow rapidly from 218 TWh/year in 2012, to 281 TWh/year by 2020, to reach 523 TWh/year by 2030.

Use electricity more efficiently by significantly expanding state-driven energy efficiency programs to improve annual electricity savings by up to 1.5 percent of retail sales per year. The calculation assumes the states and industry can rapidly expand energy efficiency programs to increase savings from 22 TWh/year in 2012, to 108 TWh/year in 2020, and to 380 TWh/year by 2029. Ultimately, EPA energy efficiency assumptions suggest that electric power savings will outpace electricity demand growth, resulting in negative electricity usage from 2020 through 2030.

Clean Power Plan – Assumption Review

This section provides a critical review of the EPA's assumptions for state-specific CO_2 emission rates and presents possible reliability challenges that need to be considered.

Building Block 1 – Coal Unit Heat Rate Improvement

The EPA's heat rate assessment analyzed gross data for 884 coal-fired electric generating units (EGUs) during a 10-year period.[12] The regression analysis examined the effects of the capacity factor and the ambient temperature on the gross heat rate efficiencies of coal-fired EGUs. The EPA's assessment concluded that in-state coal units can achieve up to a 4 percent rate of improvement through the use of best operational practices. An additional 2 percent of efficiency improvements would be achieved through capital upgrade investments.

Review of EPA Assumptions and Potential Reliability Impacts

The EPA calculated unit-specific heat rates using gross generation data from the Continuous Emission Monitoring Systems (CEMSs). With this approach, the EPA excluded generation-reducing effects from post-combustion environmental controls, such as selective catalytic reduction and flue-gas desulfurization controls. The EPA then used net generation data, without consideration for these retrofits, for coal-fired EGUs when calculating the state CO_2 emission rate goals. These retrofits will reduce the net output of these units, as well as their associated net heat rate efficiency. Not considering these reductions creates an inconsistent approach, especially considering that most coal-fired EGUs will require control retrofits to comply with environmental regulations, such as the Mercury Air Toxic Standards (MATS) and Section 316(b) of the Clean Water Act.

The EPA's regression analysis does not adjust for the following factors that have profound effects on the process efficiency of a coal-fired EGU:[13] (1) subcritical versus supercritical boiler designs; (2) fluidized bed combustion, integrated gasification combined-cycle (IGCC), and pulverized coal; (3) unit size and age; and (4) coal quality variations in moisture and ash (i.e., every 5 percent change in coal moisture results in a 1 percent change in boiler heat rate efficiency).

Impacts on Coal-Fired Unit Efficiency Rates

Lower-capacity factors will cause an increase in heat rates, particularly if the lower-capacity factors are due to the cycling of the coal units. As a result of Building Block 2, coal units will cycle more often; therefore, assumed heat rate improvements across the entire coal fleet are unlikely. While recognizing capacity effects in the regression analysis, the EPA did not evaluate the effects of lower-capacity factors resulting from the dispatching of natural gas generation before coal generation.

Periodic Turbine Overhauls

Turbine overhauls are referenced as a major heat rate improvement method in an EPA Clean Power Plan technical support document.[14] Regular turbine overhauls are generally not practical or economical, because these procedures require the unit to be out of service for an extended period of time. As well, the power industry already has multiple incentives to operate units at peak efficiency (i.e., profit maximization and competitive advantage).

Overall, improving the existing U.S. coal fleet's average heat rate by 6 percent may be difficult to achieve. Possible options and considerations for attaining a portion of this target may include the following:

- Site-specific engineering analyses are required to determine if there are remaining opportunities for heat rate improvement measures through implementation of operational best practices or capital investments.
- If the U.S. coal fleet does not achieve target heat rates, more CO_2 reductions would be required from other CPP Building Block measures.
- This can result in some coal-fired power plants retiring earlier than anticipated, which creates additional uncertainty in future generation resources.

[12] *GHG Abatement Measures* (EPA June 2014) (EPA-HQ-OAR-2013-0602) pg. 2-18.
[13] These differences are illustrated in Figure 2-2 of *GHG Abatement Measures* (EPA June 2014).
[14] Coal-Fired Power Plant Heat Rate Reductions (January 2009).

Building Block 2 – Gas Unit Re-Dispatching

The EPA assumes that reductions in CO_2 emissions from existing power plants can be achieved by dispatching existing NGCC units ahead of coal units. In particular, the EPA assumes existing NGCC units can achieve a 70 percent utilization rate with avoided incremental costs of less than $33/metric ton CO_2.[15] In its state-specific goal computation, the EPA calculated that 440 TWh/year of additional NGCC generation could potentially displace 376 TWh/year of coal and 64 TWh/year of oil-gas steam units of 2012 generation.[16]

Review of EPA Assumptions and Potential Reliability Impacts

Upon reviewing the EPA's Building Block 2 assumptions, NERC found a number of reliability concerns regarding increased reliance on natural-gas-fired generation that should be evaluated.

Historically, the primary function of the NGCC unit is to follow the load of energy throughout the day (i.e., the intermediate, or midrange, part of the load duration curve). While some NGCC units are capable of operating at a high capacity factor, the vast majority of this type of generation is used for load following. Due to lower gas prices, NGCC units are currently being dispatched as a baseload resource, displacing baseload coal-fired EGUs. Unlike baseload coal-fired generation, NGCC units are better suited to follow load. As mentioned earlier, cycling coal-fired EGUs reduces heat rate efficiencies, causing their CO_2 emission rates (lbs/MWh) to deteriorate, and further offsetting the Building Block 1 assumptions.

Generally, the power industry relies upon diversification of fuel sources as a mechanism to offset unforeseen events (e.g., abnormal weather, regional transfers, labor strikes, unplanned outages); ensure reliability; and minimize cost impacts. Fuel diversification is also a component of an "all-hazards" approach to system planning, which inherently provides resilience to the BPS. The EPA estimates that an additional 49 GW of nameplate coal capacity will retire by 2020 due to the impacts of the proposed CPP.[17] When including the 54 GW of nameplate coal capacity already announced to retire by 2020[18] (mostly due to MATS), the power industry will need to replace a total of 103 GW of retired coal resources by 2020, largely anticipated to be natural-gas-fired NGCC and CTs. Considering the current and ongoing shift in the resource mix, the EPA proposes to further accelerate the shift, lessening the industry's diversification of fuel sources.

As observed during the 2014 polar vortex,[19] the relationship between gas-fired generation availability and low temperatures challenges the industry's ability to manage extreme weather conditions—particularly when conditions affect a wide area and less support is available from the interconnection. The polar vortex served as an example of how extended periods of cold temperatures had direct impacts on fuel availability, especially for natural-gas-fired capacity. Higher-than-expected forced outages were observed during the polar vortex, particularly for natural-gas-fired generators, as a result of fuel delivery issues and low temperatures. Overall, extreme weather conditions have the potential to strain BPS reliability and expose risks related to natural-gas-fired generation availability (Figure 3). With greater reliance on natural-gas-fired generation, the resiliency and fuel diversification that is currently built into the system may be degraded, which NERC has highlighted in recent gas-electric interdependency assessments.

[15] *GHG Abatement Measures* (EPA June 2014) (EPA-HQ-OAR-2013-0602) pg. 3-26.
[16] Clean Power Plan Proposed Rule: Goal Computation – Technical Support Document http://www2.epa.gov/carbon-pollution-standards/clean-power-plan-proposed-rule-goal-computation.
[17] *Regulatory Impact Analysis for the Proposed Carbon Pollution Guidelines for Existing Power Plants and Emission Standards for Modified and Reconstructed Power Plants* (EPA June 2014 pg. 3-32).
[18] Energy Ventures Analysis maintains a complete list of announced power plant retirements in the contiguous United States, retirements as of 10/02/2014.
[19] NERC 2014 Polar Vortex Review: http://www.nerc.com/pa/rrm/January%202014%20Polar%20Vortex%20Review/Polar_Vortex_Review_29_Sept_2014_Final.pdf

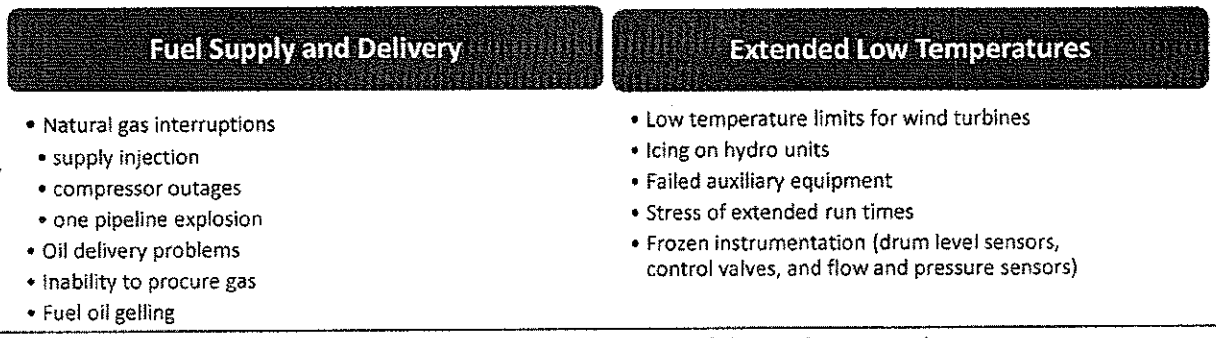


Figure 3. Causes for Generator Outages Observed during the 2014 Polar Vortex

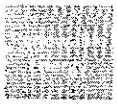
Pipeline Capacity Constraints

During its assessment of Building Block 2, the EPA concludes that the power industry in aggregate can support higher gas consumption without the need for any major investments in pipeline infrastructure. However, there are a few critical areas that likely will need additional capital investments. As an example, current and planned pipeline infrastructures in Arizona and Nevada are inadequate for handling increased natural gas demand due to the CPP. Pipeline capacity in New England is currently constrained, and more pipeline capacity additions will be needed as more baseload coal units retire—this is generally occurring as projected and independent of the CPP. Timing of these investments is also critical as it take three to five years to plan, permit, sign contract capacity, finance, and build additional pipeline capacity, in addition to placing replacement capacity (e.g., NGCC/CT units) in service. The proposed CPP timelines would provide little time to add required pipeline or related resource capacity by 2020.

Due to abundant availability of natural gas, the power industry is generally able to accommodate increased demand from NGCC plants that operate as baseload capacity. This higher dependence on natural gas can expose additional reliability risks, including pipeline transportation constraints that could result as more gas-fired generation is built. Overall, the increase in natural gas use and capacity expansion increases gas-electric interdependency issues and raises the following concerns:

- NGCC units could displace coal-fired generating units as baseload units, forcing less-efficient coal units out of service, further increasing demand for natural gas.
- Adequate timing is required to add new pipeline and generation resource capacity where it is needed to offset coal plant retirements and supply natural gas to new generation.
- As gas-electric dependency significantly increases, unforeseen events like the 2014 polar vortex could disrupt natural gas supply and delivery for the power sector in high-congestion regions, increasing the risk for potential blackouts.

Building Block 3 – Clean Energy



Building Block 3 describes the EPA's method to reduce CO_2 emissions by investing in zero-CO_2-emitting energy sources (i.e., nuclear and non-hydro renewable generation).

Review of EPA Assumptions and Potential Reliability Impacts

Building Block 3 includes the assumption about the preservation of nuclear generating units that are currently at risk of being retired within the next two decades due to (1) age, (2) an increase in fixed operation and maintenance costs, (3) relatively low wholesale electricity prices, and (4) additional capital investment associated with ensuring plant security and emergency preparedness. The EPA assumes that 5.7 percent of each state's nuclear generating capacity is at risk of retirement. However, the EPA included this generation as well as the five new nuclear units currently under construction (Watts Bar Unit 2 (TN), Summer Units 2-3 (SC), and Vogtle Units 3-4 (GA)) in its state-by-state CO_2 emission rate goal calculations.[20] The nuclear retirement assumptions add pressure to states that will need to retire nuclear units. For these states, more CO_2 reductions from other measures than originally estimated by the EPA may be required.

Under its draft CPP, the EPA also proposes significant expansion of non-hydro renewable generation as part of its BSER determination. The EPA adopted a methodology to estimate non-hydro renewable generation by state and year and applied these estimates in their calculation of individual state emission rate limitations. The greater the EPA's assumed non-hydro renewable generation in a given state, the lower the state's calculated CO_2 emission rate limit.

The EPA assumes that qualifying non-hydro renewable generation will grow from 213 TWh/year in 2012, to 281 TWh/year by 2020, reaching 523 TWh/year by 2030. These projections exceed the Energy Information Administration (EIA) non-hydro renewable generation forecast in their Annual Energy Outlook 2013 (AEO 2013) that grows from 202 TWh/year in 2012, to 275 TWh/year by 2020, to reach 317 TWh/year by 2030 for all sectors.[21] The EPA-assumed rapid growth in non-hydro renewable generation exceeds its own forecast in the EPA's *Regulatory Impacts Assessment* (356 TWh/year by 2030).[22]

To calculate the state target levels of renewable energy performance, the EPA examined mandatory state Renewable Portfolio Standard (RPS) requirements from the Database for State Incentives for Renewables and Efficiency (DSIRE).[23] RPS requirements vary widely by state; many states include resource-specific percentage requirements (i.e., set-asides) that promote development of certain resources in addition to their general requirements. The database distinguishes the complex web of state policies by applying them to a standardized tier system which, according to DSIRE, helps "to compare RPS policies on equal footing."[24] To determine the state effective levels in 2020, the EPA added each state's tiers together and excluded secondary and tertiary tiers that include energy efficiency or qualified fossil fuels (waste coal, carbon capture sequestration, etc.). The only RPS "type" considered was the primary type, referring to requirements for investor-owned utilities (IOUs).

Significant regional differences exist in the availability of renewable resources and their power production costs across the United States. In order to quantify these regional differences, the EPA divided the lower 48 states into six regions, based on designations by NERC Regions and ISO/RTOs. After the regions were assigned, the EPA averaged the 2020 effective levels for states that have mandatory RPS percentage standards. By applying the average regional renewable energy (RE) percentages to each region's aggregate 2012 generation, the EPA derived a new RE target generation level for 2030. The EPA notes that Alaska and Hawaii were assigned RE generation target percentages equal to the lowest value of the six regions, equivalent to the Southeast's target. The EPA assumes that RE generation will begin increasing in 2017 and continue through 2029. Moreover, they assume no growth occurs in between 2012 and 2016. The EPA derived the annual growth factor by determining "the amount of additional renewable generation (in megawatt-hours) that would be required beyond each

[20] *GHG Abatement Measures* (EPA June 2014) (EPA-HQ-OAR-2013-0602) pg. 4-33.
[21] *Annual Energy Outlook 2013* (EIA April 2013) reference case data.
[22] *Regulatory Impact Analysis for the Proposed Carbon Pollution Guidelines for Existing Power Plants and Emission Standards for Modified and Reconstructed Power Plants* (EPA June 2014) Table 3-11 pg. 3-27.
[23] http://www.dsireusa.org/.
[24] DSIRE. DSIRE RPS Field Definitions. April 2011. http://www.dsireusa.org/rpsdata/RPSFieldDefinitionsApril2011.pdf p.1.

region's historic (2012) generation to reach that region's RE target"[25] by 2030. This constant growth rate is then applied to each state to obtain annual state RE target levels.

The EPA's reliance on state RPS standards to compute the regional performance targets poses a variety of issues. States' main-tier RPS qualifications vary significantly and, in addition to in-state non-hydro renewable generation, also often include: hydroelectric generation, municipal solid waste (MSW), combined heat and power (CHP), clean coal, carbon capture and sequestration, and energy efficiency measures. As an example, New York has an RPS percentage of 30 percent.[26] According to the *New York Renewable Portfolio Standard Cost Study Report* produced by the New York State Department of Public Service, hydroelectricity contributes 18.25 percent of total generation and is included under baseline renewables.[27] New York's RPS percentages, therefore, include the state's hydroelectric generation as qualifying renewable resources, which is different from what the EPA assumed in its methodology.

In addition to hydroelectric power, energy efficiency plays an important role in various states' RPSs. North Carolina's RPS includes a provision that allows up to 25 percent of its target to be met by energy efficiency gains. This provision, if it were properly excluded by the EPA, would reduce North Carolina's RPS target to 7.5 percent from 10 percent, thereby lowering targets for the entire Southeast region, Alaska, and Hawaii. When establishing 2012 non-hydro renewable generation performance levels, the EPA excluded all hydroelectric generation and energy efficiency programs used in the state CO_2 emission rate calculations. The adjusted state RPS targets, as well as 2012 non-hydro RE performance levels, are used to determine the regional RE targets and regional annual growth rates.

NERC notes several other concerns with the CPP's assumption for Building Block 3, such as:

- Multipliers given to select resources' options (e.g., in-state, wind, solar, etc.). Six states (CO, DE, MI, NV, OR, and WA) give extra credit (up to 3.5 renewable energy credits per 1 MWh of energy produced) for using these resources.[28] Excluding the multiplier suggests a target that is ultimately higher than what may actually be attainable.
- The use of qualifying out-of-state renewable generation resources in effective RPS target calculations. Most RPS programs allow out-of-state qualifying renewable resources toward RPS compliance. For example, several Indiana wind projects account for nearly 50 percent of the Ohio RPS requirement. This issue is important since states realize that much of the lower-cost renewable resources may come from outside the state in locations more suitable for VERs. The underlying assumption—that the state RPS reflects in-state renewable capability that can be matched by the other states in their census region—appears incorrect and could only be dealt with via a regional state approach similar to a regional greenhouse gas initiative. In order to properly account for regional renewable resource potential, the EPA should consider including only in-state renewable resource portions of the state RPSs.
- The EPA method of assigning renewable regions is questionable. Of the six renewable regions created in the lower 48 states, targets for two regions (South Central and Southeast) were set based upon a single-state RPS. For example, the South Central state region (AR, KS, LA, NE, OK and TX) was set based upon only the Kansas RPS. Kansas accounts for only 6 percent of this region's retail power sales and has the third-best wind resources in the country. Given the combination of a low population, large land area, and very high wind resource availability, Kansas has relatively low costs to meet its RPS. However, Louisiana (ranked #48 in wind resources and double the retail sales) is assigned the same non-hydro renewable target. To put these two states in the same region sets unattainable targets for Louisiana.
- The EPA's determination of state goals for renewable generation does not fully reflect the economic aspects of renewable resources. Resource limitations exist due to permitting, market saturation, transmission access, and project financing issues. Many prime wind locations have difficulty obtaining the necessary permits and are often objected to at the local level. Many high-grade wind sites are also located in remote areas. Energy generated from

[25] *GHG Abatement Measures* (EPA June 2014) (EPA-HQ-OAR-2013-0602) pg. 4-18.
[26] http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=NY03R&re=0&ee=0.
[27] http://www.dps.ny.gov/rps/Appendix-B-2-19-04.pdf.
[28] DSIRE http://www.dsireusa.org/.

these locations requires large capital investments to build transmission infrastructure to interconnect to the BPS. Location matters, and sites with high capacity factors are limited.

- The expiration of the production tax credits (PTCs) and potential reduction of the investment tax credits (ITCs) for RE resources in the coming years will impact investment decisions and the economics of new resources. As a result, the marginal cost of new RE generation increases, which could impact the long-term development of RE resources. There is also the implicit need to increase ancillary services as a result of the increased variable resource output. Moreover, there are higher production costs associated with more non-hydro renewable generation due to a combination of increased capital costs and low-capacity operating factors. Overall, significant cost uncertainties will directly impact the electric industry's plan to quickly adapt to the CPP requirements.

Finally, grid reliability issues associated with increased variable resources are not directly addressed in the EPA's proposed Building Blocks. Conventional generation (e.g., steam and hydro), with large rotating mass, has inherent operating characteristics, or ERSs,[29] needed to reliably operate the BPS. These services include providing frequency and voltage support, operating reserves, ramping capability, and disturbance performance. Conventional generators are able to respond automatically to frequency changes and historically have provided most of the power system's essential support services. As variable resources increase, system planners must ensure the future generation and transmission system can maintain essential services that are needed for reliability.

A large penetration of VERs will also require maintaining a sufficient amount of reactive support and ramping capability. More frequent ramping needed to provide this capability could increase cycling on conventional generation. This could contribute to increased maintenance hours or higher forced outage rates, potentially increasing operating reserve requirements. While storage technologies may help support ramping needs, successful large-scale storage solutions have not yet been commercialized. Nevertheless, storage technologies support the reliability challenges that may be experienced when there is a large penetration of VERs, and their development should be expedited.

Based on industry studies and prior NERC assessments,[30] as the penetration of variable generation increases, maintaining system reliability can become more challenging. Additional assessments, including interconnection-wide studies, will be needed as the resource plans unfold to better understand the impacts.

If the states fall short of meeting the renewable energy targets established by the EPA, more CO_2 reductions from other measures may be required than were estimated by the EPA. These measures include more coal unit retirements, expanded natural gas-fired generation plants, or energy efficiency deployment.

The CPP proposes reductions in CO_2 emissions by investing in zero-CO_2-emitting energy sources (i.e., nuclear and non-hydro renewable generation). However, increased reliance on VERs creates reliability challenges that take considerable time to implement and require substantial changes in BPS planning and operations. Most notably, the challenges with this Building Block are:

- The CPP analysis relies on resource projections that may overestimate reasonably achievable expansion levels and exceed NERC and industry plans and do not fully reflect the reliability consequences of renewable resources.
- Increased reliance on VERs can significantly impact reliability operations and requires more transmission and adequate ERSs to maintain reliability.
- With a greater reliance on VERs, transmission and related infrastructure expansion lead times may not align with the CPP implementation timeline.

[29] See NERC's Essential Reliability Services Task Force website for more information: http://www.nerc.com/comm/Other/Pages/Essential-Reliability-Services-Task-Force-(ERSTF).aspx.

[30] NERC-CAISO Joint Report: Maintaining Bulk Power System Reliability While Integrating Variable Energy Resources – CAISO Approach; other industry reports include those developed by the Integration of Variable Generation Task Force (IVGTF); Integrating Variable Renewable Energy in Electric Power Markets: Best Practices from International Experience (Appendix D).

Building Block 4 – Energy Efficiency

Electricity savings from enhanced energy efficiency measures are assumed as a major reduction in U.S. power generation requirements and thereby lower U.S. power industry CO_2 emissions. In calculating individual state CO_2 emission rate limits, the EPA assumes that existing state energy efficiency programs can be significantly expanded to achieve 108 TWh in cumulative savings in 2020, continue to grow to 283 TWh by 2025, and reach 380 TWh by 2030.[31] The EPA's estimated future energy efficiency program performance will have significant effects on state compliance measures and costs.

Review of EPA Assumptions and Potential Reliability Impacts

In its *Regulatory Impact Assessment*, the EPA assumes that energy efficiency will grow faster than electricity demand, with total electricity demand shrinking beyond 2020. The implications of this assumption are complex. If such energy efficiency growth cannot be attained, more carbon reduction measures would be required, primarily from reduced coal generation in most states. More low-emitting or new NGCC/CT generating capacity (not regulated under the CPP) would need to be built. Construction of new replacement capacity, as well as related infrastructure, would take time to plan, permit, finance, and build. If these needs are not identified at an early enough stage, either grid reliability or state CO_2 emission goals could be compromised.

The EPA relied on 12 state studies to set its expanded annual program target savings improvement rate at 1.5 percent per year. However, the EPA appears to overestimate most states' energy efficiency savings potential versus prior energy efficiency projections, resulting in setting performance targets too high for individual states.[32] Savings potentials are highly state specific in their consumer mix, credit for measures already taken, and levels of subsidies provided. The EPA applies one national energy efficiency growth factor to all state situations and does not consider energy efficiency program performance or cost. The discrepancies are subsequently compounded by extrapolating these annual energy efficiency performance targets as incremental improvements that can be sustained through 2030—beyond the 12 studies evaluated.

Out of 12 studies, 11 contain multiple scenarios with different sets of assumptions to demonstrate wide ranges of what is achievable under alternative financial, technological, and behavioral environments. There is no documentation on how each study's respective average annual improvement rate was calculated, which was used as the foundation to calculate the incremental performance improvement target of 1.5 percent per year.

The assumed base year is of critical importance when comparing multiple studies' achievable potential for energy efficiency. When drawing comparisons between percentages, the baseline level of electricity demand must be the same; otherwise, the total amount of energy avoided due to energy efficiency measures would be different. Under the CPP, all energy efficiency savings are applied to Business As Usual (BAU) sales forecasts generated from EIA-861 data.[33] Base years used in the 12 studies range from as early as 2007 to as recently as 2013 and are not consistent throughout the sample.[34] Comparing achievable energy efficiency potential percentages is therefore difficult, since BAU electricity demand levels are inconsistent between the studies.

Study length is another important assumption regarding the sustainability of achievable savings. It is uncertain whether the level of annual energy efficiency savings could be sustained after the expiration of the program, as the most cost-effective and impactful measures would have been utilized already—leaving only increasingly expensive incremental energy efficiency measures. The cited studies vary significantly in length: from as few as four years, to as many as 21 years.

The CPP assumes that dividing cumulative potential by the study length provides an adequate estimation for an average annual achievable potential that is sustainable over a much longer (13-year) period (2017–2030). However, there is a discrepancy in the longitudinal application of cross-sectional studies.

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[31] EE savings estimates calculated using EPA's methodology, EE savings %, BAU sales estimates. Source: *GHG Abatement Measures* (EPA June 2014) (EPA-HQ-OAR-2013-0602) Chapter 5.

[32] Electric Power Research Institute (EPRI) and EIA.

[33] *Annual Electric Power Industry Report* (EIA 2012) (EIA 861 Data).

[34] *GHG Abatement Measures* (EPA June 2014) (EPA-HQ-OAR-2013-0602) pg. 5-65.

The CPP assumes an average life of 10 years for energy efficiency measures. This average does not fully capture the unique distribution of the length of measures when analyzing regionally available energy efficiency measures. Key assumptions when determining energy efficiency potential are "breadth of sectors and end uses considered, study period, discount rate, pattern of technology penetration, whether economically justified early replacement of technologies is allowed for, whether continued improvement in efficiency technology is provided for,"[35] yet the EPA applies a broad average rather than determining individual measure life curves. Most of the source studies perform bottom-up approaches and evaluate thousands of permutations of measures, building types, climate zones, market penetration factors, and measure lives to determine which energy efficiency technologies to include and exclude. By approximating thousands of measure lives using one average, the CPP does not capture measure life disparities and possibly underestimates the amount of energy efficiency savings that expire throughout the compliance period.

While the studies on energy efficiency consider different potentials for the three main sectors (residential, commercial, and industrial), the CPP uses one number across all sectors in its emission rate calculation. Industrial processes are designed to use as little energy as possible in order to maximize profits of daily operations and may have already invested in energy efficiency programs, leaving minimal and costly opportunities remaining for incremental improvement. Applying the same energy efficiency potential percentage for all three sectors indirectly provides incentives for industrial utility customers to reduce their energy load proportional to residential customers, but by a much greater magnitude per capita.

The underlying state and regional studies used as the base for calculating the 1.5 percent potential include the full range of financial incentives from 25 to 100 percent, when considering base, low, and high cases. Since the EPA uses an averaging method in translating from the observed studies' sector and scenario findings to the final average annual projected potential, it is difficult to evaluate the financial incentives that are assumed in both the Building Block calculations and study results.

The EPA used the EIA's AEO 2013 baseline forecast to estimate its BAU electricity sales forecast. Growth rates calculated by the National Energy Modeling System (NEMS) region were applied to state-level 2012 retail sales from the EIA-861 survey to arrive at an annual BAU sales forecast. These growth figures include the net effect of implicit forms of energy efficiency, as that information is not explicitly presented in AEO 2013 reference case. Because the EIA does not explicitly model energy efficiency as a forecast line item, the retail sales growth is skewed for the purposes of calculating the energy efficiency Building Block.

The EIA presents some metrics to gauge energy efficiency in the AEO 2013 model results. Energy intensity, defined as energy use per dollar of GDP, represents the aggregate effects of energy consumption trends and a rising national output. Electricity energy intensity, in particular, has been on a steady decline in both consumption per dollar of GDP and consumption per capita. This is due in large part to energy efficiency, but its contribution is difficult to isolate. The EIA's AEO 2013 energy load growth projections include implicit forms of energy efficiency measures, and the proposed CPP does not appear to account for these savings. This effectively double counts the savings of some energy efficiency measures and results in state-specific energy efficiency targets that are too high to be considered reasonably achievable.

With potentially overstated expectations for energy efficiency savings, the EPA's demand forecast results in a decline in electricity use between 2020 and 2030. While other major power market forecasters' electricity sales compounded annual growth rates (CAGRs) for the period between 2020 and 2030 are strictly positive (AEO 2013: 0.7 percent, EPRI: (achievable potential) 0.4 percent, NERC average of assessment studies: 1.5 percent), the EPA assumes a CAGR of -0.2 percent for the same time period. Between 2020 and 2030, the EPA assumes incremental year-over-year reductions from energy efficiency to be almost 41 TWh nationally on average, outpacing year-over-year national electricity sales growth of 31.6 TWh, on average.

The main reason for this result is the EPA's assumption of states being able to sustain an annual incremental growth rate in energy efficiency savings of 1.5 percent once achieved. As mentioned above, this sustainability is not supported by any peer-reviewed or technical studies of energy efficiency potential.

[35] *GHG Abatement Measures* (EPA June 2014) (EPA-HQ-OAR-2013-0602) pg. 5-22.

By overestimating efficiency savings resulting in declining electricity retail sales, the results of the EPA's entire *Regulatory Impact Assessment* are concerning from a reliability perspective and have implications to electric transmission and generation infrastructure. Underlying electricity demand forecasts directly influence the required level of generation—and hence, CO_2 emissions—from existing and affected generating units under the CPP. They also affect the required new construction of generating units that are needed to meet expected electricity demand, which is projected to increase during the next 10 years.[36]

The EPA projection for energy efficiency growth at a 1.5 percent annual increase is substantially greater compared to what NERC examined in its current and prior long-term reliability assessments (LTRAs). NERC collects energy efficiency program data that is embedded in the load forecast for each LTRA assessment area. Projected annual energy efficiency growth as a portion of Total Internal Demand since 2011 has ranged from only 0.12 to 0.15 percent, as shown in the table below.

Table 1. 2011–2014 LTRA Energy Efficiency Growth

LTRA	10-Year Growth of EE (%)	Portion of Total Internal Demand (%)		Annual Growth in Relation to Total Internal Demand (%)
		Year 1	Year 10	
2011	10.7	0.59	1.63	0.12
2012	12.2	0.72	1.88	0.13
2013	11.6	0.92	2.02	0.12
2014	13.4	0.87	2.25	0.15

In summary, the CPP assumes energy efficiency gains outpace electricity demand growth through the compliance period. However, this assumption does not reasonably reflect energy efficiency achievability and is a departure from normalized forecasts. If states are unable to achieve the EPA target savings, additional CO_2 reduction measures beyond BSER measures would be needed to meet the proposed rate limits—primarily through further reductions in existing generation or expansion of natural gas and VERs. The energy efficiency assumptions underpin the CPP proposal and present the following reliability issues:

- The EPA appears to overestimate the amount of energy efficiency expected to reduce electricity demand over the compliance time frame. The results of overestimation have implications to electric transmission and generation infrastructure needs.
- Substantial increases in energy efficiency programs exceed recent trends and projections. Several sources, including but not limited to NERC, EIA, EPRI, and various utilities, have published reports, analysis, and forecasts for energy efficiency that do not align with the CPP's assumed declining demand trend.
- The CPP assumption appears to underestimate costs and may underestimate the capital investments that would be required by utilities to sustain energy efficiency performance through 2030.
- The offsetting requirements in more coal retirements, along with expansions in natural gas and VERs, in a constrained time period could potentially result in reliability or ERS constraints.

[36] *NERC 2014 Long-Term Reliability Assessment.*

Reliability Impacts Potentially Resulting from the CPP

To meet the proposed CPP emission reduction levels, the states are expected to select the mass-based limitation approach over the emission rate approach due to its greater flexibility, as well as ease to enforce and implement. The power industry has been successful in complying with prior mass-based emission cap and trade programs (e.g., Acid Rain program, Clean Air Interstate Rule, and RGGI) without creating reliability impacts. The CPP introduces potential reliability concerns that are more impactful than prior environmental compliance programs due to the extensive impact to fossil-fired generation. Additionally, there is potential for an accelerated decision-making period for the implementation of the CPP's Building Blocks. It is also important to consider the ongoing transformation to the resource mix and corresponding impacts on ERSs required to maintain a reliable BPS. State-specific carbon intensity targets create potential reliability concerns in two major areas: (1) direct impacts to resource adequacy and electric infrastructure, and (2) impacts resulting from the changing resource mix that occur as a result of replacing retiring generation, accommodating operating characteristics of new generation, integrating new technologies, and imposing greater uncertainty in demand forecasts.

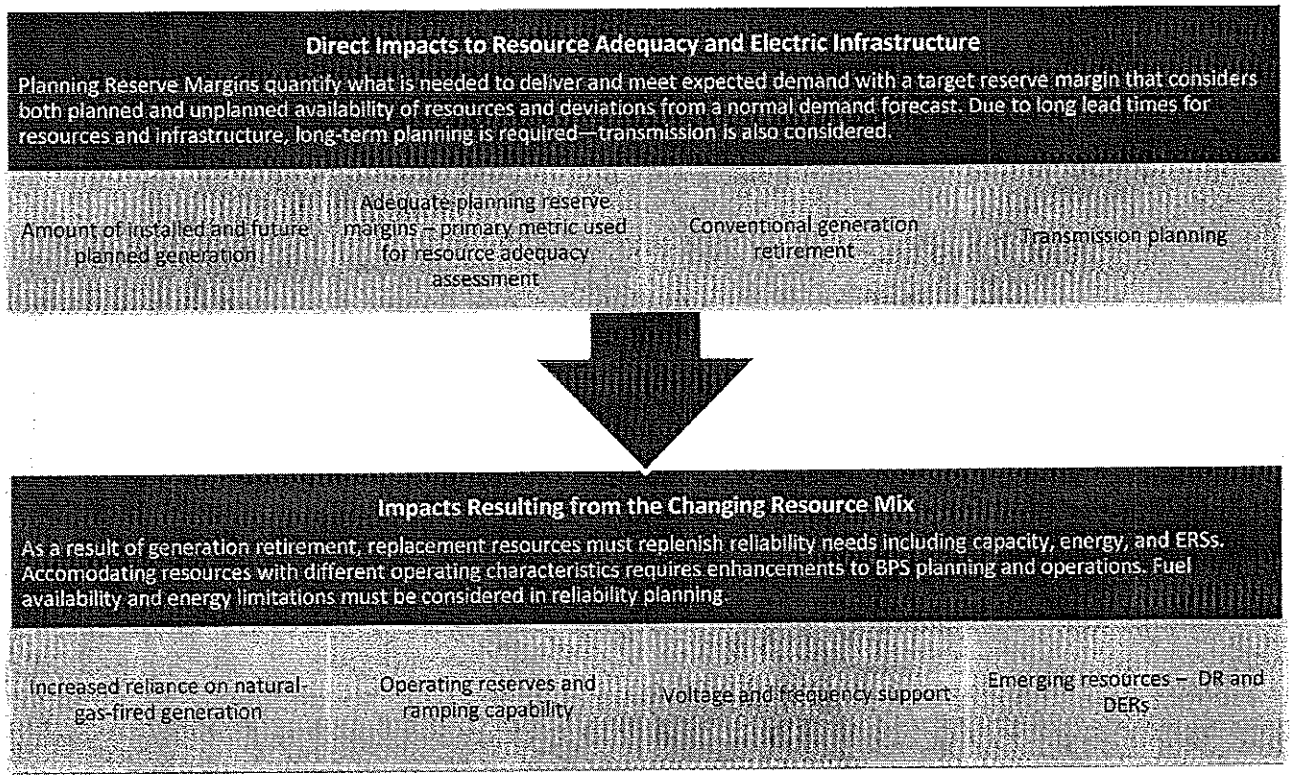


Figure 4. Summarized Reliability Challenges

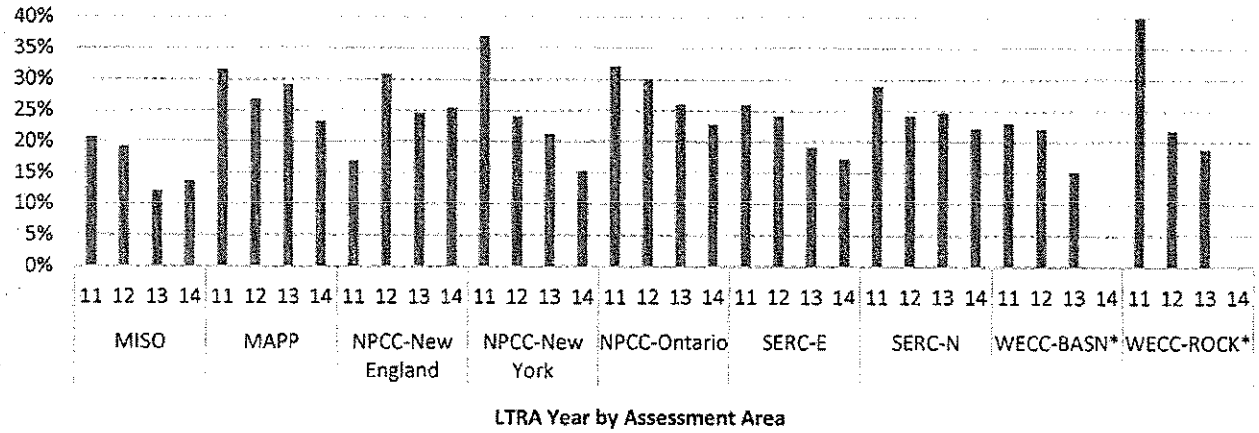
Most importantly, generation (along with other system resources) and transmission must provide specific capabilities to ensure the BPS can operate securely under a myriad of potential operating conditions and contingencies, in compliance with a wide range of NERC planning and operating Reliability Standards. The above challenges warrant further consideration by policy makers. The following sections discuss these key reliability challenges in detail.

Direct Impacts to Resource Adequacy and Electric Infrastructure

Fossil-Fired Retirements Result in Accelerated Declines of Reserve Margins

In recent long-term assessments, NERC has highlighted resource adequacy concerns, particularly in ERCOT, NPCC-New York, and MISO, as projections continue to reflect declining reserve margins that fall below each area's Reference Margin Level over the next five years, despite low demand growth rate (Figure 5). As most LTRA assessment areas attribute stagnant demand growth to the ongoing projected economic indicators (typically based on either employment levels or GDP) in the

residential, commercial, and industrial sectors, total capacity additions have paralleled the ongoing declines in load growth. The trend of declining margins in a number of NERC assessment areas is rooted primarily from a general reduction in 10-year capacity additions observed over the past several years. Total capacity additions continue to fall behind the ongoing declines in load growth rates (Figure 6).[37]



*Due to changes to the WECC subregional boundaries, resulting in four subregions instead of nine, the 2014 Anticipated Reserve Margins are not shown for WECC-BASN and WECC-ROCK for this comparison.

Figure 5. Short-Term (Year 2 Forecast) Anticipated Reserve Margins Show Declining Trends for Some Assessment Areas

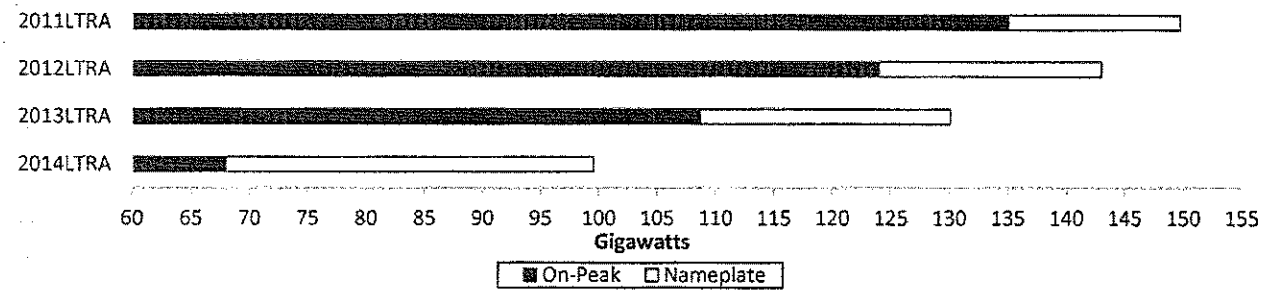


Figure 6. NERC-Wide 10-Year Projected Capacity Additions Declining Since 2011

The EPA's supporting documents estimate that up to 19 percent of the nation's coal plants will become "uneconomical" as a result of the proposed CPP. Although the CPP may not become enforceable until 2020, its effect may overshadow and change large retrofit capital decisions needed to comply with earlier EPA regulations—primarily MATS.

According to the EPA, the state implementation would result in a reduction in coal to 193 GW by 2025. The EPA finalized MATS, which is factored into *2014 LTRA* and identifies capacity retirements through 2016. In its *Technical Support Document – Resource Adequacy and Reliability Analysis,* the EPA used the Integrated Planning Model (IPM) to project likely future electricity market conditions with and without the proposed CPP. The IPM assumed that adequate transmission capacity exists to deliver any resources located in, or transferred to, the individual regions. Additionally, since most regions currently have capacity above their target reserve margins, the EPA assumed most of the retirements are absorbed by a reduction in excess reserves over time. However, uncertainty remains for a large amount of existing conventional generation that may be vulnerable to retirement resulting from additional pending EPA regulations. These retirements reduce reserve margins over the course of the CPP implementation.[38]

[37] 2011, 2012, and 2013LTRA data includes Future-Planned capacity additions http://www.nerc.com/pa/RAPA/ra/Pages/default.aspx.
[38] EPA Technical Support Document –Resource Adequacy and Reliability Analysis http://www2.epa.gov/sites/production/files/2014-06/documents/20140602tsd-resource-adequacy-reliability.pdf.

The EPA's analysis assumes the electric system will maintain resource adequacy, even with the ongoing retirements from existing regulations, including MATS. In addition, because the proposed CPP will require the development of significant amounts of new generation in a short period, additional time for infrastructure development will be needed to support these new resources. The EPA's modeling of a potential implementation scenario predicts an additional 40–48 GW of fossil-fired EGU retirements, and the addition of 21 GW of new NGCC resources.

With existing environmental regulations, the EPA's base case projections indicate that total coal-fired capacity will decline rapidly from 309.6 GW in 2013 to just 245 GW by 2016, and 243 GW by 2025. The EPA's base case—without implementation of the proposed CPP—assumes a significant reduction in coal-fired capacity by 2016: 27.2 GW beyond what is currently projected in the *2014LTRA* reference case. According to the *2014LTRA* reference case, an additional 44.2 GW of fossil-fired and nuclear capacity is projected to retire between 2014 and 2024.[39] These projections are based on the assumption that current environmental regulations will remain and do not account for potential impacts from the proposed CPP (Figure 7).

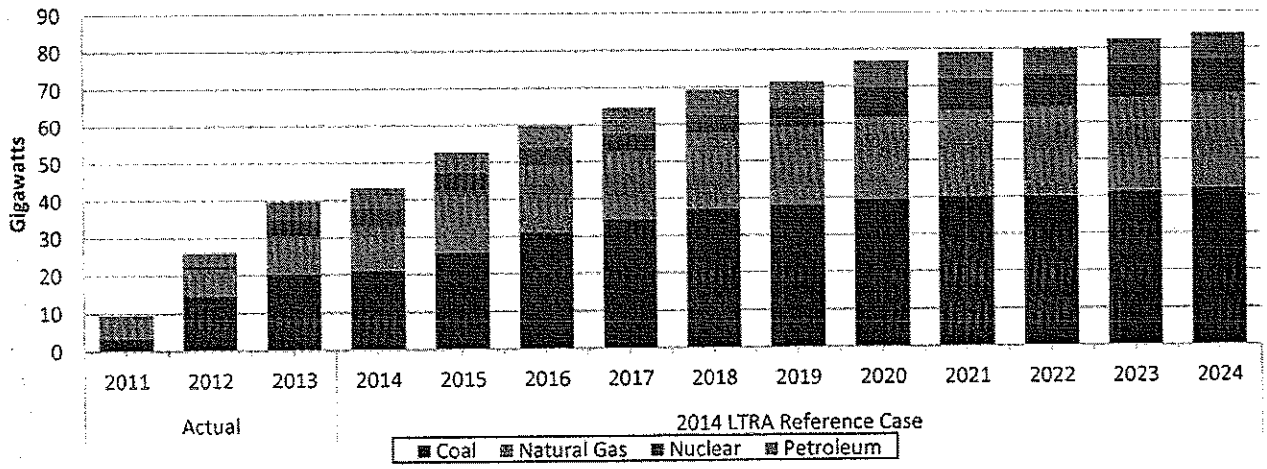


Figure 7. Cumulative Fossil-Fuel and Nuclear Retirements between 2011 and 2024 Total 83 GW

According to the EPA, the state implementation of Option 1 would result in a reduction in coal to 193 GW by 2025. Option 1 and the *2014LTRA* reference case are shown in Figure 8 and Table 2.[40]

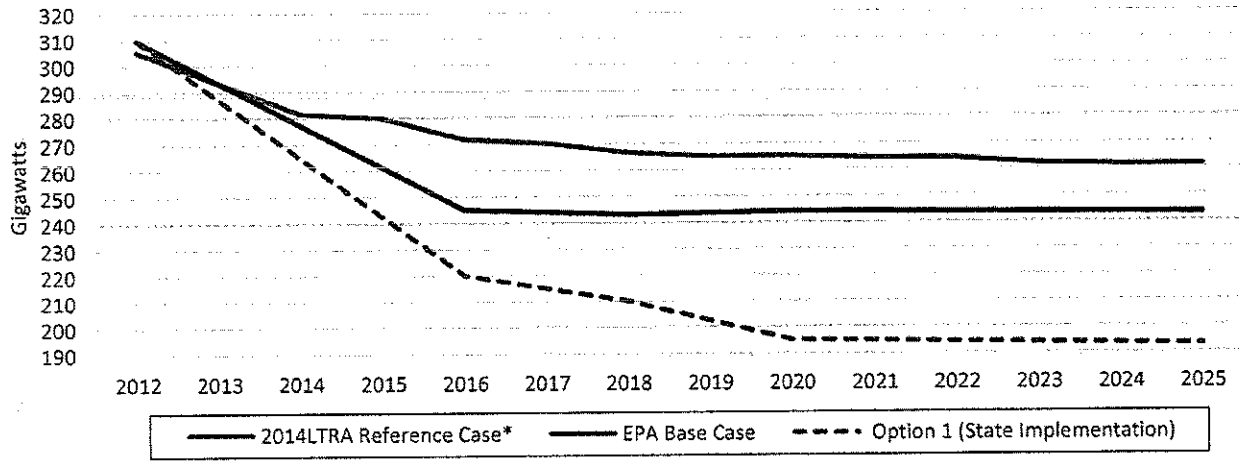


Figure 8. 2014LTRA Reference Case & EPA Power Plan Assumptions: Coal-Fired Capacity

[39] While the assessment period for the *2014LTRA* is 2015–2024, projected retirements for 2014 are included in NERC's *2014LTRA* analysis.

[40] *Regulatory Impacts Analysis for the Proposed Carbon Pollution Guidelines for Existing Power Plants and Emission Standards for Modified and Reconstructed Power Plants* (June 2014) and supporting IPM Model documentation and data.

Table 2. 2014LTRA Reference Case & EPA Power Plan Assumptions

NERC 2014LTRA Reference Case - Total On-Peak Capacity (GW)	2016	2018	2020	2025*
Total Coal (Existing-Certain and Tier 1 Capacity Additions)	271.8	266.4	264.9	261.3
EPA Analysis of the Proposed Clean Power Plan - Total Coal Generating Capacity (GW)	2016	2018	2020	2025
Base Case	244.6	243.3	243.6	243.3
Option 1 (State Implementation)	219.7	210.4	195.1	193.1
EPA Assumed Coal Reduction Beyond NERC 2014LTRA Reference Case (GW)	2016	2018	2020	2025
Base Case	27.2	23.1	21.3	18.0
Option 1 (State Implementation)	52.1	56.0	69.8	68.2

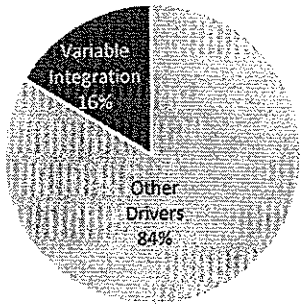
Transmission Planning and Timing Constraints

Long lead times for transmission development and construction require long-term system planning—typically a 10–15-year outlook. In addition to designing, engineering, and contracting transmission lines, siting, permitting, and various federal, state, provincial, and municipal approvals often take much longer than five years to complete. The CPP analysis assumes that adequate transmission capacity is available to deliver any resources located in, or transferred to, the region.[41] Given the significant changes and locations anticipated to occur in the resource mix, it is likely that additional new transmission, or transmission enhancements, will be necessary in some areas. New transmission lines will be required to transport the amount of renewable generation coming online, particularly in remote areas, and that creates additional timing considerations. Further, as replacement generation is constructed, new transmission may be needed to interconnect new generation. Mitigating transmission constraints identified from the proposed EPA regulations in a timely way, consistent with CPP targets, presents a potential reliability concern. Construction of new interstate high-voltage lines would require transmission owners to confer to state and federal laws with respect to environment impacts, siting, and permitting. A construction timeline for a new high-voltage line can range from 5 to 15 years depending on the voltage class, location, and availability of highly skilled construction crews. The construction of transmission assets is a very lengthy process starting from planning to the actual physical construction. It is recommended that any policies that could potentially impact the reliable operation of the transmission system also consider the associated timeline for implementing plans.

Transmission Considerations with Additional VERs

The projected 30.8 GW of additional wind and solar resources will require additional transmission to reliably integrate these resources. VERs are often built in parts of North America that are distant from the point of interconnection to the transmission system. In many cases, the location of these variable resources only meets the minimum voltage support requirements. According to the 2014LTRA Reference Case, 16 percent of new transmission projects (under construction, planned, or conceptual) identify variable resource integration as a primary driver.

New Transmission Project Drivers



The location of additional transmission resources will be informed by the outcome of the transmission planning studies. The transmission planning process will not be able to fully incorporate the impacts of potential retirements until those resource addition requirements are made known to the system operator. For ISO/RTOs, this will likely not happen until the final state plans are developed.

To support variable generating capacity increases, the power industry would need to invest heavily to expand transmission capacity to access more remote areas with high-quality wind resources. Developing a resource mix that has sufficient ERSs to support integration and reliable BPS operation is also a consideration. Given the natural wind variability in these locations, incremental wind project resources would have relatively low capacity factors (20–35 percent) that would require complex financial decisions to support transmission capacity.

[41] *Regulatory Impacts Analysis for the Proposed Carbon Pollution Guidelines for Existing Power Plants and Emission Standards for Modified and Reconstructed Power Plants* (June 2014) and supporting IPM Model documentation and data.

NERC anticipates that after the CPP guidelines are finalized in 2015, and SIPs are developed and approved by the EPA in 2016/2017, entities will work with their state utility commissions or other appropriate governing entities to assess resource and system options. Extensive transmission reliability screening assessments will be performed to support these decisions and will include comprehensive local and regional reliability analyses, which must be coordinated with states and neighboring entities. As resource decisions are made, reliability screening will transition into the established NERC reliability assessment processes. Consistent with the NERC Reliability Standards, transmission enhancements to address reliability constraints will be identified, incorporated into transmission expansion plans, and coordinated with other projects locally and regionally. Because committed transmission projects typically require three to five years to be completed, and often longer for major projects with significant right-of-way needs, NERC is concerned that reliability-related enhancements may not be able to be completed for a 2020 implementation.

Initial Regional Reliability Assessment of the Proposed CPP

Some regions started an initial reliability assessment of the proposed CPP focused on their respective footprints to better understand the plan's potential impacts. The initial analyses are slightly different in focus and are in varying stages of development. The key findings from recent MISO and SPP studies are provided below.

MISO

MISO focused primarily on generation capacity impacts. MISO, which is based on a 14.8 percent reserve margin requirement determined by the 1-day-in-10-year loss-of-load event, projects that in in 2016 it will operate at the reliability level of approximately 2-days-in-10-year loss-of-load event, increasing the likelihood that resources will not be sufficient to serve peak demand. The number of expected days per year of a loss-of-load event is projected to increase throughout the assessment period. The proposed CPP could further exacerbate resource adequacy concerns in the MISO footprint unless additional replacement capacity is built in a timely fashion.[42] Additionally, the analysis showed that the EPA's carbon proposal could put an additional 14,000 MW of coal capacity at risk of retirement. This amount is beyond the 12,600 MW within MISO's footprint that is slated to retire by the end of 2016 to comply with MATS.[43] The contributing factors driving the projected deficit include:

- Increased retirements and suspensions (temporary mothballing) due to EPA regulations and market forces and low natural gas prices
- Exclusion of low-certainty resources that were identified in the resource adequacy survey
- Exclusion of surplus of capacity in MISO South above the 1,000 MW transfer from the Planning Reserve Margin requirement (PRMR)[44]
- Increased exports to PJM and the removal of non-Firm imports[45]
- Inadequate Tier 1 capacity additions[46]

[42] Anticipated Reserve Margin includes operable capacity expected to be available to serve load during the peak hours with firm transmission. Prospective Reserve Margin operable capacity that could be available to serve load during the peak hour, but lacks Firm transmission and could be unavailable for a number of reasons.

[43] MISO GHG Regulation Impact Analysis – Initial Study Results.

[44] For this assessment, 1,000 MW of capacity is transferred from the MISO South to the MISO North/Central Region pending the outcome of regulatory issues currently under FERC review.

[45] Capacity sales (imports and exports) in MISO depend on decisions of the respective resource owners, assuming that the tariff requirements are met (including planning of necessary transmission of both the buying and selling areas). Regarding the removal of non-Firm imports, the MISO market monitor double-counted non-Firm imports in the 2013LTRA reference case. These imports are accounted for in the Reference Margin Level (PRMR).

[46] In the MISO footprint, 91 percent of the load is served by utilities with an obligation to serve customers reliably and at a reasonable cost. Resource planning and investment in resources are part of state and locally jurisdictional integrated resource plans that only become certain upon the receipt of a Certificate of Public Convenience and Necessity (CPCN).

SPP

SPP looked at both generation capacity and transmission reliability impacts of the proposed CPP.[47] The initial study indicated that compliance with the carbon regulations, if implemented as modeled by the EPA, will not be possible without significant investment in new generation and associated major improvements to both the electric transmission and natural gas infrastructure to accommodate new generation. The results indicate that by 2020, SPP's anticipated reserve margin would be 5 percent, representing a capacity margin deficit of approximately 4,500 MW. By 2024, 10,000 MW beyond current plans would be needed to maintain their reserve margin. Given the 8- to 10-year timeline needed to plan for and construct these additional resources, SPP has concluded that there is not sufficient time to achieve compliance with the EPA's interim goals, and that widespread reliability impacts are likely.

The reliability issues identified in the initial studies will require significant upgrades to the transmission infrastructure to maintain system reliability, accommodate new generation or, when new generation is not warranted, to support the dispatch of the system in a manner significantly different from historical operations. Other ISO/RTOs, states, and Regions should prepare for the potential impacts to grid reliability, especially related to the time required to plan and build transmission infrastructure.

Reliability Assurance

NERC Reliability Standards and Regional Entity criteria must be met at all times to ensure reliable operation and planning of the BPS. Therefore, NERC supports policies developed by the EPA, FERC, the DOE, and state utility regulators that include a "reliability assurance mechanism," such as a reliability back-stop, to preserve BPS reliability and manage emerging and impending risks to the BPS.

Many utilities and ISO/RTOs have discussed a possible reliability safety valve similar to the one-year compliance extension that has been used to avoid retirement-related reliability impacts from the MATS compliance deadline. A reliability safety valve will be of limited utility if the EPA's proposal is implemented as currently designed, and it appears the EPA has far more flexibility under Section 111(d) than was available under the Section 112 program. Accordingly, a set of reliability assurance provisions that may include a reliability backstop, as well as other measures, would be recommended to maintain BPS reliability.

Stakeholders expressed to NERC staff their concerns regarding the need for additional time to mitigate the impacts of the carbon regulation. The proposed timeline does not provide enough time to develop sufficient resources to ensure continued reliable operation of the electric grid by 2020. To attempt to do so would increase the use of controlled load shedding and potential for wide-scale, uncontrolled outages. Additionally, policy changes may be required to ensure the Planning Coordinators and Transmission Planners perform the necessary studies and exercise the authority to implement transmission and related infrastructure solutions and assure that ERSs are provided in a timely manner.

[47] SPP Reliability Assessment of EPA 111(d) Clean Power Plan Rule http://www.spp.org/publications/SPC%20Materials%20081914.pdf.

Direct Impacts to Resource Adequacy and Electric Infrastructure
Summary and Recommendations

Fossil-Fired Retirements and Accelerated Declines in Reserve Margins: Despite low demand growth, NERC has highlighted resource adequacy concerns as projections continue to reflect declining reserve margins that fall below the Reference Margin Level in three assessment areas within the next five years.

- *The Regions, ISO/RTOs, and states should perform further analysis to examine the potential resource adequacy concerns.*

Transmission Planning and Timing Constraints: The proposed CPP implementation is currently scheduled to begin in mid-2016. Some reliability impacts could be mitigated by the construction of new (or enhancement of existing) transmission facilities; however, long lead times (e.g., 10 years) are required for transmission planning and construction.

- *The EPA and states, along with industry, should consider the time required to integrate potential transmission enhancements and additions necessary to address impacts of the proposed CPP.*

Regional Reliability Assessment of the Proposed CPP: To better understand its potential impacts, some Regions have started an initial reliability assessment of the proposed CPP focused on their respective footprints. The initial analyses are slightly different in focus and are in varying stages of development.

- *Other ISO/RTOs, states, and Regions should prepare for the potential impacts to grid reliability, especially related to the time required to plan and build transmission infrastructure.*

Reliability Assurance: NERC Reliability Standards and Regional Entity criteria must be met at all times to ensure reliable operation and planning of the BPS.

- *The EPA, FERC, the DOE, and state utility regulators should employ the array of tools at their disposal and their regulatory authority to develop reliability assurance mechanisms such as a reliability back-stop. These mechanisms include timing adjustments and granting extensions where there is a demonstrated reliability need.*

Impacts Resulting from the Changing Resource Mix

Coal Retirements Increase Reliance on Natural Gas for Electric Power

The electricity sector's growing reliance on natural gas raises concerns regarding the electricity infrastructure's ability to maintain system reliability when facing a constrained natural gas capacity for delivering natural gas to electric power generators. These concerns are already being articulated in light of gas-electric dependency studies and analyses, and include ISO/RTOs, electricity market participants, industrial consumers, national and regional regulatory bodies, and other government officials.[48] The extent of these concerns varies from region to region; however, concerns are most acute in areas where power generators rely on interruptible pipeline transportation as the natural gas use for generation rapidly grows.

Under the CPP, an accelerated shift in the power generation mix from coal to natural gas is expected to ensue. The EPA's state limitation calculations assume a 440 TWh/year shift to existing NGCC generation from coal (376 TWh/year) and older oil-gas steam (64 TWh/year) generators due to redispatched NGCC units up to a 70 percent capacity factor. In its *Regulatory Impact Assessment*, the EPA projects that the natural gas market portion of total U.S. power generation will grow from 29 percent energy in 2013 to 33–34 percent from 2020 to 2030. In an analysis of the CPP prepared by Energy Ventures Analysis (EVA), natural gas generation is found to increase by an additional 400–450 TWh/year and increase the gas generation energy market share to reach 35 percent in 2020, 39 percent in 2030, and 49 percent in 2040.[49]

As reliance increases more on natural gas for both baseload and on-peak capacity, it is important to also examine potential risks associated with reduced diversity and increased dependence on a single fuel type. Currently, natural-gas-fired resources account for large portions of both the total and on-peak resource mix in several assessment areas when considering both existing capacity and planned additions (Table 3).

Table 3. Assessment Areas with Natural-Gas-Fired Capacity Accounting for Over One-Third of Existing Nameplate Capacity[50]

	Nameplate Capacity (GW)		On-Peak Capacity (GW)		10-Year Nameplate Capacity Additions (GW)		
Assessment Area	Gas-Fired	Portion of Total	Gas-Fired	Portion of Total	Tier 1	Tier 2	Tier 3
FRCC	40.2	64%	33.9	63%	10.1	0.0	0.0
MISO	69.0	39%	58.7	41%	2.8	0.0	10.0
NPCC-New England	18.6	54%	13.3	43%	1.1	3.3	0.0
NPCC-New York	21.0	55%	14.2	40%	0.0	3.5	0.0
PJM	80.0	43%	56.5	32%	10.0	47.5	0.0
SERC-SE	31.2	47%	28.4	46%	0.0	0.0	2.6
SPP	32.3	40%	30.2	47%	1.1	0.7	5.7
TRE-ERCOT	48.4	54%	45.2	63%	4.9	21.5	0.0
WECC-CA/MX	47.7	61%	43.9	70%	5.5	6.2	0.9
WECC-RMRG	7.2	36%	6.2	41%	1.2	0.0	0.0
WECC-SRSG	19.5	47%	16.3	50%	0.6	1.0	3.0

With this shift toward more natural gas consumption in the power sector, the power industry will become increasingly vulnerable to natural gas supply and transportation risks. Extreme conditions, although rare, must be studied and integrated in planning to ensure a suitable generating fleet is available to support BPS reliability. While there are several plants with dual-fuel capability, the capability to switch to a secondary fuel can be limited during certain operating conditions.

Overdependence on a single fuel type increases the risk of common-mode or area-wide conditions and disruptions, especially during extreme weather events. Disruptions in natural gas transportation to power generators have prompted the gas and electric industries to seek an understanding of the reliability implications associated with increasing gas-fired generation. For example, adverse winter weather, such as that experienced during January 2014, provided signs of natural gas supply and deliverability risks.[51] This can be a local issue in areas where there is already a heavy concentration of natural gas generation.

[48] See NERC's Special Reliability Assessments on electric and gas interdependencies for more information and recommendations: Phase I and Phase II.

[49] Energy Ventures Analysis: FUELCAST – The Long-Term Outlook 2014, October 2014.

[50] Tier 1, 2, and 3 Capacity Category Definitions are provided in the *2014 Long-Term Reliability Assessment.*

[51] NERC Polar Vortex Review Report
http://www.nerc.com/pa/rrm/January%202014%20Polar%20Vortex%20Review/Polar_Vortex_Review_29_Sept_2014_Final.pdf

While several gas pipeline construction projects are underway to increase gas deliverability, the CPP proposal accelerates the shift toward more natural gas generation and could create additional pipeline needs. The increased demand can be addressed with sufficient lead time (i.e., more than three years), which is needed to plan, collect contracts, permit, procure, and build new pipeline. To the extent that the CPP assumptions regarding natural-gas-fired capacity expansion and existing coal-fired generation retirements are achieved, the gas and electric sectors will lean more heavily on each other.

The Availability of Essential Reliability Services Is Strained by a Changing Resource Mix

The proposed CPP provides states and developers additional incentives to rapidly expand their non-hydro renewable capacity to displace existing coal generation. The state calculations assume that non-hydro renewable capacity could grow rapidly by 5 percent per year, from 218 TWh/year in 2012 to reach 523 TWh/year by 2030. This incremental renewable generation represents well over twice the energy currently supplied by VERs and would be dominated mostly by new wind, and to a lesser extent, new solar capacity.

In addition, wind projects will significantly increase the demand for reactive power and ramping flexibility. Ramping flexibility will increase cycling on conventional generation and often results in either increased maintenance hours or higher forced outage rates—in both cases, increased reserve requirements may result. While storage technologies may help support ramping needs, successful large-scale storage solutions have not yet been commercialized.[52] Storage technologies support the reliability challenges that may be experienced when there is a large penetration of VERs, and their development should be expedited.

Based on industry studies and prior NERC assessments,[53] as the penetration of variable generation increases, maintaining voltage stability can be more challenging. Additional studies will be needed to further understand potential challenges that may indirectly result from the proposed CPP. In its role of assessing reliability, NERC commissioned the Essential Reliability Services Task Force (ERSTF) with members from NERC's Planning Committee and Operating Committee to study, identify, and analyze the planning and operational changes that may impact BPS reliability. NERC, under the ERSTF work plan and activities, has issued an initial assessment of ERSs that identifies ERS reliability building blocks as a foundational approach for further assessment and studies.[54]

Increased Penetration of Distributed Energy Resources

The EPA projects that retail electricity prices will increase by $1/MWh to $18/MWh under the CPP[55] as a result of a combination of higher natural gas prices and the implementation of new carbon penalties on impacted fossil-fired generators.[56] As retail power prices increase, some existing customers may install DERs, when economically advantageous. Depending on the price advantage, the market penetration of DERs could be substantial, creating potential reliability impacts for grid operators that lack visibility and control of these resources. Given that DERs displace grid retail sales, DERs could become a larger grid capacity planning challenge since the grid will remain responsible for being the DER site's back-up power supplier. Reliability issues with large onsets of non-dispatchable resources have already created operational challenges in California, Hawaii, and Germany. Such experienced reliability challenges are:

- The loss of inertia and the loss of generating units used to control transient instability driven by the significant non-controllable generation and lack of sufficient attention to ERSs—Hawaii.

[52] Pumped storage offers fast and large ramping capabilities to the BPS; however, increases in this technology is not likely due to land restrictions, permitting limitations, and environmental opposition. Less than 1 GW of pumped storage capacity is projected over the next 10 years.

[53] NERC-CAISO Joint Report: Maintaining Bulk Power System Reliability While Integrating Variable Energy Resources – CAISO Approach; other industry reports include those developed by the Integration of Variable Generation Task Force (IVGTF); Integrating Variable Renewable Energy in Electric Power Markets: Best Practices from International Experience (Appendix D)

[54] NERC Essential Reliability Services Task Force - A Concept Paper on Essential Reliability Services that Characterize Bulk Power System Reliability http://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/ERSTF_Draft_Concept_Paper_Sep_2014_Final.pdf

[55] *Regulatory Impacts Analysis for the Proposed Carbon Pollution Guidelines for Existing Power Plants and Emission Standards for Modified and Reconstructed Power Plants* (June 2014) and supporting IPM Model documentation and data.

[56] According to EIA, closing coal plants will drive up natural gas prices by 150 percent over 2012 levels by 2040, this cost rise will cause electricity prices to jump seven percent by 2025 and 22 percent by 2040. Because natural gas prices are a key determinant of wholesale electricity prices, which in turn are a significant component of retail electricity prices. Accordingly, the cases with the highest delivered natural gas prices also show the highest retail electricity prices. 2014 Annual Energy Outlook.

- DERs only operate within frequency ranges that are in many cases close to nominal frequency and, therefore, frequency and voltage ride-through capabilities are needed—Germany.
- Increased wind and solar levels that mandate increased ramping, load-following, and regulation capability—this applies to both expected and unexpected net load changes. This flexibility will need to be accounted for in system planning studies to ensure system reliability—California.

Studies and Assessments Needed to Support Reliability

The following assessments are needed to form a complete reliability evaluation. Table 4 provides a list of the types of studies and analysis that must be done to demonstrate reliability, recognizing that the industry does not operate the grid without a thorough and complete analysis.

Table 4. Study and Assessment Types Needed for a Complete Reliability Evaluation

Local Reliability Assessments	Area/Regional Reliability Assessments
• Specific generator retirement studies • Specific generator interconnection studies • Specific generator operating parameters • Power flow (thermal, voltage) • Stability and voltage security • Offsite power for nuclear facilities	• Resource adequacy • Power flow (regional) • Stability and voltage security (regional) • Gas interdependencies; pipeline constraints • Operating reserves and ramping • System restoration/blackstart

Impacts Resulting from the Changing Resource Mix
Summary and Recommendations

Coal Retirements and the Increased Reliance on Natural Gas for Electric Power: As the industry relies more on natural-gas-fired capacity to meet electricity needs, close examination will be necessary to ensure risks have been fully identified and evaluated. Potential issues are most acute in areas where power generators rely on interruptible natural gas pipeline transportation.

- *Further coordinated planning processes between the electric and gas sectors will be needed to ensure a strong and integrated partnership. Coordinated planning processes should include considerations for pipeline expansion to meet the increased reliance on natural gas for electric generation—especially during the extreme weather events (e.g., polar vortex).*

The Changing Resource Mix and Maintaining Essential Reliability Services: The proposed CPP provides states and developers additional incentives to rapidly expand their non-hydro renewable capacity to displace existing coal generation. Resource adequacy assessments do not fully capture the ERSs needed to reliably operate the BPS and are generally limited to identifying supply and delivery risks.

- *ISO/RTOs, utilities, and Regions, with NERC oversight, should analyze the impacts to ERSs in order to maintain reliability. Additionally, system operators and ISO/RTOs need to develop appropriate processes, tools, and operating practices to adequately address operational changes on the system.*
- *NERC should perform grid-level performance expectations developed from a technology-neutral perspective to ensure ERS targets are met.*
- *The development of technologies (such as electricity storage) help support the reliability objectives of the BPS, and these technologies should be expedited to support variability and uncertainty on the BPS.*

Increased Penetration of Distributed Energy Resources: A potential risk in additional DERs is the temporary displacement of utility-provided service, which could create additional planning challenges, considering utilities must act as a secondary supplier of electricity.

- *ISO/RTOs and system planners and operators should consider the market penetration of DERs and potential reliability impacts due to the limited visibility and controllability of these resources.*

Conclusions

This report represents NERC's initial review of reliability concerns regarding the EPA's proposed Clean Power Plan (CPP) under Section 111(d) of the Clean Air Act. As the CPP is finalized and implemented, NERC will develop special reliability assessments in phases. This initial evaluation highlights the underlying CPP assumptions and identifies a range of potential reliability impacts of the CPP on the BPS. It is NERC's intention that this document be used as a platform by industry stakeholders and policy makers to discuss technically sound information about the potential reliability impacts of the proposed CPP.

The Building Block assumptions in the EPA's proposed CPP are critical to NERC's evaluation of the reliability impacts. NERC will provide independent assessments of the BPS under a wide range of conditions that reflect the implications of the proposed policy, varied resource mixes, and impacts to transmission and will share the results with the industry and states as they develop their implementation plans.

Recommendations

1. **NERC should continue to assess the reliability implications of the proposed CPP and provide independent evaluations to stakeholders and policy makers.**
   The NERC Board of Trustees endorsed a plan for the review and assessment of the reliability impacts of the EPA proposal at its August 2014 Board meeting. The NERC Planning Committee should lead NERC and industry efforts in conducting the reliability assessments and scenario analyses as identified in this report. NERC will work through its stakeholder process to solicit industry input on assessment approaches and assumptions as further special assessments and evaluations are developed.

2. **Coordinated regional and multi-regional industry planning and analysis groups should immediately begin detailed system evaluations to identify areas of concern and work in partnership with policy makers to ensure there is clear understanding of the complex interdependencies resulting from the rule's implementation.**
   Given the potential reliability concerns of the EPA's 2020 proposed implementation date, NERC encourages the states to begin operational and planning scenario studies, including resource adequacy, transmission adequacy, and dynamic stability, to assess economic and reliability impacts. A number of studies and analyses must be performed to demonstrate reliability, and industry must closely coordinate with the states to ensure the SIPs are aligned with what is technically achievable within the known time constraints. Additionally, industry should review system flexibility and reliability needs while achieving the EPA's emission reduction goals. As a result, states that largely rely on fossil-fuel resources might need to make significant changes to their power systems to meet the EPA's target for carbon reductions while maintaining system reliability.

3. **If the environmental goals are to be achieved, policy makers and the EPA should consider a more timely approach that addresses BPS reliability concerns and infrastructure deployments.**
   NERC Reliability Standards and Regional Entity criteria must be met at all times to ensure reliable operation and planning of the BPS. Based on NERC's initial review, more time would be needed in certain areas to ensure resource adequacy, reliability requirements, and infrastructure needs are maintained. The EPA, FERC, the DOE, and state utility regulators should consider their regulatory authority to make timing adjustments and to grant extensions to preserve BPS reliability. NERC supports policies that include a reliability assurance mechanism to manage emerging and impending risks to the BPS, and urges policy makers and the EPA to ensure that a flexible and effective reliability assurance mechanism is included in the rule's implementation.

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Walking the Line Between the Clean Air Act and the Federal Power Act: Balancing Emission Reductions and Bulk Power Reliability

A power plant can find itself subject to potential liability under the Clean Air Act if it does not cease or greatly reduce operations and at the same time be compelled by the Department of Energy and/or the Federal Energy Regulatory Commission acting under the Federal Power Act to keep operating to ensure reliability. There needs to be cooperation among the federal agencies to create a stable and predictable regulatory environment at a minimum and, more preferably, a comprehensive solution to prevent this conflict from occurring in the first place.

Michael Gergen, Claudia O'Brien, Eli W.L. Hopson and David E. Pettit

Recent rounds of regulations by the Environmental Protection Agency (EPA) have renewed a critical unresolved legal question for operators of power plants, one that impacts the reliability of the nation's bulk power grid: What happens when a plant is subject to potential liability under the Clean Air Act (CAA) if it does not cease or greatly reduce operations, and at the same time is compelled by the Department of Energy (DOE) and/or the Federal

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Energy Regulatory Commission (FERC) acting under the Federal Power Act (FPA) to keep operating to ensure reliability? Although this scenario may arise for plants installing emission control systems to obtain compliance with the CAA, conflict between the CAA and the FPA is more likely to arise for plants seeking to retire rather than install control systems for which reliability solutions such as new generation or transmission upgrades are not practical under the time constraints imposed by the CAA. In this article we summarize the statutory background for such potential conflicts between the CAA and the FPA, explore previous instances where these laws were in conflict, and discuss the recent regulations and how conflicts arising under them might be addressed by EPA, DOE, and FERC.

I. Bulk Power Reliability and the Federal Power Act

Both DOE and FERC have ways to address bulk power reliability concerns pursuant to various provisions of the FPA. DOE has invoked its authority several times since 2000, while FERC has only invoked its authority once and in a manner complementary to authority already exercised by DOE.

A. DOE's authority under the FPA

Section 202(c) of the FPA empowers the Secretary of Energy to order power plants to operate for reliability reasons during emergency situations. The statute specifically provides that "whenever the Commission determines that an emergency exists ... the Commission shall have authority ... to require by order such temporary connections of facilities and such generation, delivery, interchange, or transmission of electric energy as in its judgment will best meet the emergency and serve the public interest."[1]

Conflict between the CAA and FPA is more likely to arise for plants seeking to retire rather than install control systems for which reliability solutions such as new generation or transmission upgrades are not practical.

Even though the language in the FPA refers to "the Commission," the authority to require power plants to operate in fact lies with the Secretary of Energy and DOE. The Department of Energy Organization Act transferred the powers previously vested with the Federal Power Commission to DOE unless the authority is expressly reserved to FERC.[2] While DOE has vested certain powers with FERC, such as those provided in Sections 202(a) and 202(b) of the FPA, DOE has retained its authority under Section 202(c).

Not only has DOE retained this authority, it has interpreted its potential application broadly. DOE has defined an "emergency" to include, among other things, "an unexpected inadequate supply of electric energy."[3] Perhaps presciently, DOE also included "regulatory action which prohibits the use of certain electric power supply facilities" in its definition of "emergency."[4]

However, Section 202(c) does not require DOE to take action; instead, it simply provides DOE with the authority to take action if it so chooses. As discussed in more detail below, DOE has invoked this authority in several instances since 2000.

B. FERC's authority under the FPA

Section 202(c) is not the only provision of the FPA that appears to provide a federal agency with the authority to ensure the reliability and adequacy of electric service. Section 207 of the FPA states that upon a complaint by a state commission, "[w]henever the Commission ... shall find that any interstate service of any public utility is inadequate or insufficient, the Commission shall determine the proper, adequate or sufficient service to be furnished, and shall fix the same by its order, rule or regulation ...."[5]

While this authority lies with FERC, it has only been invoked on one occasion—and in that instance, DOE had already ordered a plant to generate

electricity pursuant to Section 202(c). Specifically, in 2006, FERC used its authority under Section 207 to require PJM Interconnection, LLC, (PJM) and the Potomac Electric Power Company ("Pepco") to "file a long-term plan to maintain adequate reliability in the Washington, DC, area and surrounding region, and a plan to provide adequate reliability pending implementation of this long-term plan."[6] Aside from this instance, FERC has refrained from using this authority.[7]

However, Section 207 arguably allows FERC to consider reliability concerns in determining whether a utility is providing adequate or sufficient service.[8] While FERC's authority is contingent upon a complaint by a state commission, Section 207 mandates that FERC take action to remedy the problem upon a finding of inadequate service.[9] In contrast, Section 202(c) simply provides DOE with the discretion to take action, though DOE can do so on its own accord.[10]

Section 309 of the FPA augments FERC's authority by permitting it "to perform any and all acts, and to prescribe, issue, make, amend, and rescind such order, rules, and regulations as it may find necessary or appropriate to carry out the provisions of [the FPA]."[11] Courts, however, have narrowly construed Section 309, stating that it "merely augment[s] existing powers"[12] and allows FERC to "use means of regulation not spelled out in detail."[13] As such, FERC would most likely need to rely on another provision, perhaps in conjunction with Section 309, to address reliability concerns.

II. EPA's Authority under the Clean Air Act to Regulate Power Plants

EPA has broad authority to regulate power plant operation. For coal fired-power plants, EPA has recently proposed and in some cases finalized new regulations that would affect emissions of pollutants, handling of the byproducts of coal combustion, and cooling-water intake structures. These regulations are promulgated under the CAA, the Resource Recovery and Conservation Act (RCRA), and the Clean Water Act (CWA), respectively. Although all of the rules published by EPA have the potential to impact reliability, EPA's recently finalized emissions limits for hazardous air pollutants and for pollutants that cross state lines for utility-scale energy generating units will be the first to impact operating power plants. As the RCRA rules relating to coal combustion byproducts and the CWA rules on cooling water intakes are still in the draft stage, with no clear statutory deadline for implementation, we focus our discussion on the potential conflict between the CAA rules and FERC and DOE's responsibilities under the FPA.

Section 207 arguably allows FERC to consider reliability concerns in determining whether a utility is providing adequate or sufficient service.

A. EPA's authority under the CAA

1. National Ambient Air Quality Standards

EPA is directed under Section 109(b)(1) of the CAA to create national standards, the National Ambient Air Quality Standards (NAAQS), to limit levels of pollutants that are harmful to public health and welfare.[14]

The CAA is a partnership of federal and state regulation, with Section 110 directing each state to adopt a State Implementation Plan (SIP), which EPA must then approve.[15] Once approved, the SIP is effectively a federal law, and enforceable as such.[16] The CAA further provides that once approved, no federal entity "shall engage in, support in any way, or provide financial assistance for, license or permit, or approve, any activity which does not conform to an implementation plan after it has been approved ...."[17] The statute defines conformity as:

"(A) conformity to an implementation plan's purpose of eliminating or reducing the severity and number of violations

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of the [NAAQS] and achieving expeditious attainment of such standings; and

(B) that such activities will not -

(i) cause or contribute to any new violation of any standard in any area;

(ii) increase the severity of any existing violation of any standard in any way; or

(iii) delay timely attainment of any standard or any required interim emission reductions or other milestones in any area."[18]

Although broadly drafted, there are limitations on the scope of the conformity requirement. Initially, the conformity analysis only covers "major" federal actions; for actions emitting less than the threshold, conformity is presumed.[19] *De minimis* actions are also explicitly excluded by regulation.[20] EPA's regulations also specifically exclude "actions in response to emergencies or natural disasters such as hurricanes, earthquakes, *etc.*, which are commenced on the order of hours or days after the emergency or disaster" or "actions which are a part of a continuing response" to said emergency or disaster, although the federal agency taking the action must make a written determination that the conformity analysis is impractical for a period of up to six months "due to overriding concerns for public health and welfare, national security interests and foreign policy commitments."[21] CAA Section 110(f) also contains a non-delegable Presidential temporary waiver for energy emergencies, which is limited to a period of four months.[22] Some courts have interpreted EPA's authority to act pursuant to the CAA as discretionary, with the court in *Seabrook v. Costle* noting that no section of the CAA "imposes a mandatory duty on the Administrator to make a finding every time some information concerning a possible violation of a SIP is brought to [her] attention."[23]

Although broadly drafted, there are limitations on the scope of the conformity requirement.

The NAAQS provisions of the CAA do not directly address conflicts with other laws.

2. *Mercury and Air Toxics Standards*

EPA is directed under Section 112 to regulate power plant emissions of hazardous pollutants. Congress required EPA to study power plant emissions of hazardous air pollutants under Section 112(n)(1). Following presentation of that study to Congress, the statute required EPA to regulate power plants "if the Administrator finds such regulation is appropriate and necessary."[24] EPA issued a determination that regulating the emissions of hazardous air pollutants from power plants was "appropriate and necessary" in 2000,[25] and promulgated regulations that have since been vacated by the D.C. Circuit.[26] Subsequently several environmental and public health organizations filed a complaint alleging that EPA had not performed a mandatory duty under the CAA to regulate hazardous air pollutants from coal and oil-fired electrical generating units (EGUs).[27] EPA settled the case, and under the consent decree was required to issue a notice of final rulemaking by Dec. 16, 2011.[28]

The Mercury and Air Toxics Standards (MATS) standards for existing power plants are technology-based emissions limits, with the Administrator required to set levels equivalent to the average emissions of the best-performing 12 percent of plants.[29] EPA must set the effective date no later than three years after the rule is published.[30] Under the CAA, either the administrator or a delegated state may issue an extension of up to one year "if such additional period is necessary for the installation of controls."[31] The President may also grant an exemption for up to two years if "the President determines that the technology to implement such standard is not available and that it is in the national security interests of the United States to do so."[32]

As with the NAAQS, there is no language under the MATS that clarifies how to resolve conflicts with other laws. Similarly, there is no language in the other sections of the CAA. The CAA does generally provide authority for citizen suits against any person, including the administrator, for violations of the act or failure of the administrator to perform a required duty.[33]

III. Past Conflicts between the CAA and the FPA

Bulk power reliability concerns have led DOE to exercise its authority under Section 202(c) of the FPA on several occasions since 2000. For example, DOE ordered the Cross-Sound Cable, an underwater transmission line running between Connecticut and Long Island, to operate during back-to-back summers due to a summer heat wave in 2002[34] and the Northeast Blackout in 2003.[35] However, there have been two instances in recent years where some electric power generators have faced a dilemma between complying with the CAA and following an order under the FPA to generate electricity.

A. The Potomac River Generating Station

The Potomac River Generating Station is a 482 MW coal-fired power plant in Alexandria, Va., that provides electricity for portions of the District of Columbia, including the Blue Plains Advanced Water Treatment Plant—one of the largest wastewater treatment plants in the world.[36] On Aug. 19, 2005, Mirant Corporation, the owner of the station, submitted a computerized emissions model to the Virginia Department of Environmental Quality (VDEQ) indicating that emissions from the station either caused or contributed to localized exceedances of the NAAQS.[37] In response to a subsequent letter from VDEQ, Mirant shut down all five of the station's generating units on Aug. 24, 2005.[38]

Bulk power reliability concerns have led DOE to exercise its authority under Section 202(c) of the FPA on several occasions since 2000.

That same day, the District of Columbia Public Service Commission (DCPSC) filed a petition with both DOE and FERC requesting that Mirant be compelled to operate the station to maintain reliability in the District of Columbia.[39] Based on the "reasonable possibility an outage will occur that would cause a blackout," DOE responded to the DCPSC's petition by ordering Mirant to resume operations pursuant to Section 202(c) of the FPA.[40] FERC also responded by requiring long-term reliability plans from PJM and Pepco pursuant to Section 207 of the FPA.[41]

DOE's order to resume operation did not, however, expressly alleviate Mirant from possible penalties for exceeding the NAAQS. In its order, DOE sought to walk the line between reliability and potentially adverse environmental impacts by specifying the manner in which Mirant was to operate the station. DOE also stated that if EPA issued a compliance order, then DOE would consider whether and how to conform its order accordingly.[42] Sure enough, six months later, EPA issued a compliance order instructing Mirant to use SO_2 emission controls and to operate only when daily modeling indicated that it would comply with the NAAQS.[43] However, the compliance order also required Mirant to operate the station "as specified by PJM and in accordance with the [2005] DOE Order."[44]

Mirant successfully operated the station pursuant to the orders by DOE and EPA for over a year. On Feb. 23, 2007, however, Mirant's luck ran out. By operating in accordance with DOE's order to run for reliability purposes, the station exceeded its three-hour NAAQS limit and the VDEQ consequently fined Mirant for NAAQS exceedances.[45] This situation was unfortunately not the first time a

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generator faced a dilemma involving the CAA and the FPA.

B. The California Energy Crisis

Near the end of 2000 and into 2001, the state of California experienced an unexpected electricity shortage. DOE responded by ordering certain generation facilities to make energy available to the California Independent System Operator (CAISO) for a period of approximately two months.[46] In addition to the action taken by DOE, FERC also instituted a "must-offer obligation" mandating that all non-hydroelectric generators offer all of their available capacity into the spot market during all hours.[47] In light of comments filed by generators, FERC recognized that the must-offer obligation could result in generators operating in violation of their certificates or applicable law. To mitigate this situation, the must-offer requirement did not require generators to run if doing so would otherwise break the law.[48] In a subsequent order, FERC clarified that a generator could go so far as to seek a declaratory order from the courts finding that compliance with the must-offer obligation would result in permit violations if it wanted to prevent citizen suits alleging violations of environmental regulations.[49] This clarification came about in response to a citizen suit against a generator, which the generator settled at a significant cost.[50]

IV. Potentially Potent Rulemakings

A. EPA's finalized regulations

1. *Cross-State Air Pollution Rule*

On July 6, 2011, EPA finalized regulations requiring significant reductions in SO_2 and NO_x emissions.[51] EPA issued the regulations in response to the D.C. Circuit's remand of a prior version of the rule, the Clean Air Interstate Rule (CAIR).[52] EPA proposed technical adjustments on Oct. 6, 2011, and finalized a supplemental rule including additional states on Dec. 17, 2011.[53] EPA estimates that costs associated with CSAPR are $800 million annually in 2014, on top of $1.6 billion per year in capital investments that were being made in response to the previous rulemaking.[54] EPA expects facilities to use dry and wet flue-gas desulfurization (FGD), dry sorbent injection, selective catalytic reduction (SCR), and some fuel switching and process optimization.[55] The initial compliance phase was to begin on Jan. 1, 2012; however, the D.C. Circuit stayed CSAPR on December 30, 2011 in *EME Homer City Generation, L.P. v. EPA* and ordered the parties to propose briefing schedules so that the case could be heard by April 2012.[56] As the rule stands now, the second, more stringent compliance phase begins on Jan. 1, 2014.[57]

2. *MATS for Utility Generators*

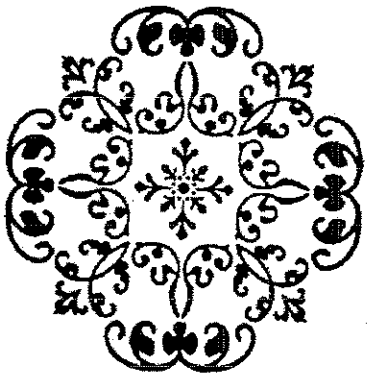
On Dec. 16, 2011, EPA finalized regulations limiting the emissions of mercury and other hazardous pollutants from EGUs.[58] EPA estimates that the total cost of the rule will be $9.6 billion annually in 2015.[59] Some industry estimates are significantly higher.[60] EPA expects plants that are installing controls to use a mixture of available technologies, including SCR with FGD, activated carbon injection (ACI), ACI with a fabric filter, dry sorbent injection, and electrostatic precipitators.[61] Costs for individual plants will vary, but for facilities with no pollution controls, compliance costs are expected to run into the hundreds of millions of dollars per plant.[62] EPA made small revisions to the proposal as a result of comments received, which according to EPA's estimates reduced the costs of compliance by about $1 billion.[63]

EPA grants the statutory maximum of three years and 60 days from the published date for compliance with the MATS rule, meaning the earliest compliance date would be March 2015.[64] As discussed above, generators that are installing controls may be

eligible for an additional one-year extension from either the state managing the program or the administrator.[65] In two memoranda released with the final rule, one from EPA and one from the President, the administration states that although unlikely to be required, EPA can issue administrative orders that would absolve violators who were operating subject to critical reliability concerns of complying with the CAA for one year under Section 113(a) (governing enforcement of violations).[66] However, as discussed above, prior experiences indicate that the administrative order process may not protect against all risks to companies required to operate for reliability reasons, as citizen suits may be filed by individuals or organizations other than EPA. The memoranda also make clear that the administration intends to make the standard one-year extension for installation of controls under Section 112 (i)(3)(b) "broadly available"; however, the applicability of that extension to facilities that plan on retiring is uncertain.[67] Neither memorandum mentions the President's authority under Section 112 (i)(4), so the breadth of that additional exemption, and the administration's willingness to invoke it, are unclear.

B. EPA's proposed regulations

EPA has also proposed two other rules that are likely to have a significant cost impact on certain coal-fired electrical generating units, potentially including some that are critical to reliability. The first rule, proposed on June 21, 2010,[68] with a subsequent Notice of Data Availability issued on Oct. 12, 2011,[69] deals with the treatment of coal combustion byproducts. Two regulatory schemes were proposed by EPA under RCRA, with the first being to regulate coal



combustion residuals under Subtitle C of RCRA, which covers the cradle-to-grave treatment of hazardous waste. EPA's second proposal would regulate the coal byproducts under Subtitle D of RCRA, the section regulating non-hazardous wastes. EPA has indicated that a final rule will not be issued until late 2012; thus the nature of the regulation and the timeline for implementations are unclear.[70]

The second proposed regulation is for the intake of cooling water. EPA has proposed regulations that would cover the impingement (trapping of fish against the intake screen) and entrainment (fish that are drawn into the power plant and affected by heat or other stress) of fish and other aquatic life.[71] EPA has signed a consent decree with the environmental group Riverkeeper indicating that it will issue final actions by July 27, 2012, although the implementation period for existing plants is still unknown.[72]

C. Anticipated impacts on bulk power reliability

At least a dozen studies have attempted to analyze the potential reliability impacts associated with the recent suite of new regulations by EPA. However, all of these studies face the same problem—we do not have all of the final rules yet, and companies' responses to the finalized rules are still being developed.

At FERC's recent Reliability Technical Conference, PJM pointed out that there is a chicken-or-the-egg issue with respect to identifying the impacts on reliability that the proposed rules will have before EPA issues its final rules.[73] The problem is that reliability impacts cannot be reliably estimated until generators identify which units they will retire. At the same time, generators cannot know which units to retire until they have all of the final rules from EPA and have had time to analyze the final regulations. So, in the meantime, the best approach is to attempt to identify all "at risk" generation to understand the possible spectrum of reliability impacts.[74] As a result, there is a variety of studies that make varying assumptions and come to sometimes

dramatically different conclusions.[75]

Regardless of the extent of retirements anticipated across the country, the situation with the Potomac River Generating Station indicates that the early retirement of even a single plant can lead to a localized reliability issue. Accordingly, DOE, FERC, and EPA should take steps to coordinate the implementation of these rules in a predictable manner that does not place generators in the position faced by the Potomac River Generating Station.

V. Potential Outcomes for Resolving Reliability Conflicts

EPA, FERC, utilities, and regulators have all proposed a number of different solutions for resolving any potential conflict. We discuss below a number of the solutions that have been proposed or that are present in the underlying statutes. These solutions can generally be grouped into three categories: actions by EPA or the states to waive environmental laws, Presidential extensions, or actions by DOE or FERC to force regulated entities to violate environmental laws, while potentially protecting those entities.

A. Reliability safety valve

Although this phrase has been incorporated into a number of different proposals describing different mechanisms, most commonly the "reliability safety valve" refers to a proposal put forward in joint comments on the MATS proposed rule from several independent system operators (ISOs) and regional transmission organizations (RTOs).[76] The Joint RTO Commentors proposed that a retiring generator that is determined to be critical for system reliability be allowed to operate for an additional fourth year, or longer if more time is required to address the reliability issue.[77] The RTO comments propose limiting the extension to situations where the generator provides an early notice of impending retirement, the ISO/RTO identifies the unit as critical to reliability, and the upgrades or replacements necessary to address the reliability problem are expected to take more than three years.[78]

EPA has adopted some aspects of this proposal into its enforcement memorandum issued with the final MATS rule, although the additional extension for units critical to reliability would operate *via* administrative order under Section 113(a), and would be limited to a period of one year.[79] On the other hand, neither the Presidential memo nor EPA enforcement memorandum clarify whether the separate "broadly available" one-year extension under Section 112(i)(3)(B) would be available to facilities that are shutting down.[80] Notably EPA indicates that the administrative orders under Section 113(a) would be granted to facilities that are moving into retirement, not just for facilities installing controls, or being replaced with new generation onsite.[81] Potentially more problematic is EPA's statement that the orders would not be issued before the compliance date, creating the potential for a conflict until the order is posted.[82] In addition, the administrative orders may not remove risks from citizen suits, as previously discussed in the context of the California energy crisis.

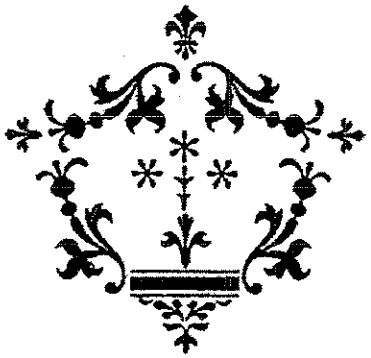
A longer-term solution could be to amend the FPA to make clear that those operating under an emergency order issued by DOE pursuant to its authority under Section 202(c) of the FPA are not subject to civil or criminal liability for violating environmental laws or regulations.[83] This has the advantage of addressing any future concerns under other environmental statutes, but may be challenging to pass in a tough legislative environment.

B. Presidential extensions

Under both CSAPR and MATS, the CAA includes a Presidential waiver that could be used to temporarily extend compliance deadlines for individual facilities. While the administration has not expressed a view as to the potential for use of these statutory exemptions, they remain possible uses for particular situations. Although the CSAPR exemption is limited to only four months by the statute, the Presidential exemption under Section 112 could theoretically be reissued indefinitely for two-year terms if required. Given the potential for long timelines for siting new power plants and transmission lines, this backstop authority may become useful if the other extensions EPA has proposed are exhausted.

C. Compelled operation to protect bulk power reliability

If an extension, consent decree, or similar waiver cannot be obtained for a unit that is critical to reliability, DOE might choose, as it has previously, to apply its authority under FPA Section 202(c) to require a facility to run. Yet none of the issues raised by the Potomac River and California Energy Crisis situations discussed above have been resolved, leading to significant uncertainty for plant operators. Under FERC's supervision, units that are critical to reliability and planning to retire may be able to negotiate distributed financial burdens for installing controls, or indemnity against any future costs.[84] Alternatively, similar to the FERC's approach during the California energy crisis, any orders that require a generating facility to operate could be limited so as to make clear that the order would not apply if compliance would result in a violation of the facility's certificate or applicable law.



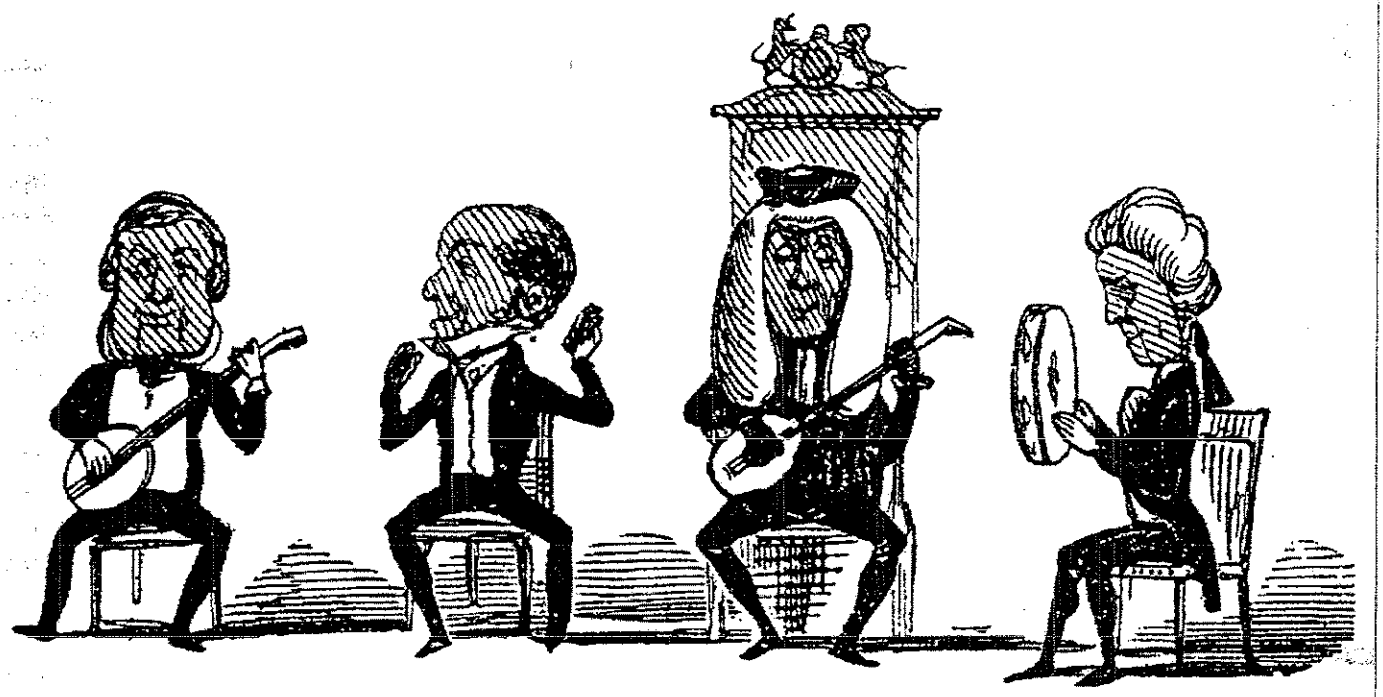
VI. Which Statute Controls if Another Conflict Arises?

Despite the numerous proposals and possible coordination among federal agencies, it is plausible that another conflict will occur between the CAA and the FPA, just as it did with respect to the Potomac River Generating Station. If another conflict occurs, the question of which statute controls may very well come before the courts.

A court will first look to the statutes to see if either specifically addresses conflicts of law.[85] In this case, neither the CAA nor the FPA expressly or impliedly trump one another. In the absence of a conflicts-of-law provision, a court will then attempt to harmonize the provision so as to avoid the conflict.[86] As discussed above, there is a potentially critical difference between Sections 202(c) and 207 of the FPA in that DOE's authority under Section 202(c) is discretionary, while Section 207 mandates FERC to "fix" inadequate service. Courts have held that certain environmental statutes must yield if their application prevents a federal agency from fulfilling a nondiscretionary legislative mandate.[87] Because of the nondiscretionary mandate of Section 207, a court could find that FERC's action pursuant to Section 207 cannot be waived or limited by conflicting CAA provisions.[88]

However, a court may not be able to harmonize Section 202(c) of the FPA and the CAA amendments in the more likely event that DOE orders a generating facility to operate such that it violates the NAAQS.[89] In such a scenario, courts will apply two basic principles of statutory interpretation: (1) the more recent statute controls, and (2) the more specific statute controls.

Congress amended the CAA in 1970 to implement the NAAQS. In 1935, Congress enacted Sections 202, 207, and 309 of the FPA. Based on these facts, a court could determine that the CAA amendments repealed by implication the conflicting



There needs to be cooperation among the federal agencies to create a stable and predictable regulatory environment.

provisions of the FPA.[90] However, courts disfavor a finding that a statute was repealed by implication and will look to determine whether the legislative intent to repeal was clear and manifest.[91] Here, such a determination would be unlikely because there is no evidence that Congress intended the CAA amendments to repeal any conflicting provision of the FPA.

Moreover, a more specific statute will control over a more general one.[92] The more specific statute may even take priority over another statute enacted by Congress more recently.[93] Here, both statutes require specific directives to be applied to individual generating facilities. The CAA calls for EPA to regulate generating facilities and mandate compliance with the NAAQS. The FPA, on the other hand, provides the authority to require certain plants to operate for reliability purposes as directed by DOE. Thus, while both statutes provide specific directives, it is not unlikely that a court could find that Section 202(c) of the FPA supersedes the CAA.

Regardless of whether the CAA or the FPA (Section 202(c) and/or Section 207) controls, there needs to be cooperation among the federal agencies to create a stable and predictable regulatory environment at a minimum and more preferably, a comprehensive solution to prevent this conflict from occurring in the first place.■

Endnotes:

1. 16 U.S.C. § 824a(c).
2. *See* 42 U.S.C. § 7151(b).
3. 10 C.F.R. § 205.371.
4. *Id.*
5. 16 U.S.C. § 824f.
6. *District of Columbia Public Service Commission*, 114 FERC ¶ 61,017 at P 2 (2006).
7. *See, e.g., Arkansas Public Service Commission v. Entergy Service, Inc. et al.*, 119 FERC ¶ 61,223 (2007).
8. William L. Massey, Robert S. Fleishman and Mary J. Doyle, *Reliability-Based Competition in Wholesale Electricity: Legal and Policy Perspective*, 25 ENERGY L.J. 319, 329 (2005).

9. 16 U.S.C. § 824f.

10. 16 U.S.C. § 824a(c).

11. 16 U.S.C. § 825h.

12. *New England Power Co. v. Fed. Power Comm.*, 467 F.2d 425, 430 (D.C. Cir. 1972).

13. *Niagara Mohawk Power Corp. v. Fed. Reg. Energy Comm.*, 379 F.2d 153, 158 (D.C. Cir. 1967).

14. 42 U.S.C. § 7409.

15. 42 U.S.C. § 7410.

16. *See, e.g., Her Majesty the Queen v. City of Detroit*, 874 F.2d 332 (9th Cir. 1989) (holding that once a SIP is approved by the EPA, its requirements become federal law and are fully enforceable in federal court).

17. 42 U.S.C. § 7506(c)(1).

18. *Id.*

19. *See* 40 C.F.R. § 51.853(b) – (c).

20. 40 C.F.R. § 51.853(c).

21. *Id.* §§ 51.853(d)(2), (e).

22. 42 U.S.C. § 7410 (f).

23. *City of Seabrook v. Costle*, 659 F.2d 1371 (5th Cir. 1981) ("*Seabrook*"); *see also Yakima v. Surface Transp. Bd.*, 46 F.Supp. 2d 1092 (E.D. Wa. 1999).

24. 42 U.S.C. § 7412(n)(1).

25. 65 Fed. Reg. 79826-27 (Dec. 20, 2000).

26. *New Jersey v. EPA*, 517 F.3d 574, 583 (D.C. Cir. 2008).

27. American Nurses Association, Chesapeake Bay Foundation, Inc., Conservation Law Foundation, Environment America, Environmental Defense Fund, Izaak Walton League of America, Natural Resources Council of Maine, Natural Resources Defense Council, Physicians for Social Responsibility, Sierra Club, The Ohio Environmental Council, and Waterkeeper Alliance, Inc. (Civ. No. 1:08-cv-02198 (RMC)), *at:* http://www.epa.gov/ttn/atw/utility/consentfnl.pdf.

28. Note that the original date of Nov. 16, 2011, was modified by consent of the parties, as described in paragraph 7(b). *Id.*

29. 42 U.S.C. § 7412 (d)(3).

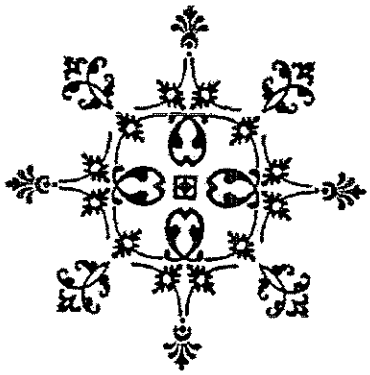
30. 42 U.S.C. § 7412 (i)(3).

31. *Id.*

32. 42 U.S.C. § 7412 (i)(4).

33. 42. U.S.C. § 7604 (a).

34. DOE Order 202-02-1, Order Pursuant to Section 202(c) of the Federal Power Act (Aug. 16, 2002).



35. DOE Order 202-03-1, Order Pursuant to Section 202(c) of the Federal Power Act (Aug. 14, 2003); DOE Order 202-03-2, Order Pursuant to Section 202(c) of the Federal Power Act (Aug. 28, 2003).

36. *District of Columbia Public Service Commission*, DOE Order 202-05-3 at 2–3 (Dec. 20, 2005), *at* http://www.gc.doe.gov/sites/prod/files/oeprod/DocumentsandMedia/mirant_122005_2.pdf (hereinafter "2005 DOE Order").

37. *Id.* at 1.

38. *Id.* Mirant subsequently resumed operating one unit for 16 hours of each 24-hour period prior to DOE's order that it released on Dec. 20, 2005. Both EPA and VDEQ acknowledged that this minimal operation of the station did not result in NAAQS exceedances. *Id.* at 3.

39. Emergency Petition and Complaint of the District of Columbia Public Service Commission, Docket Nos. EO-05-01 (DOE), EL05-145-000 (FERC) (filed Aug. 24, 2005).

40. 2005 DOE Order at 6. As an example of the potential ramifications of a blackout, Pepco stated that "within 24 hours of the loss of electric supply, Blue Plains will have no option but to release untreated sewage directly into the Potomac River." *Id.* at 4.

41. *District of Columbia Public Service Commission*, 114 FERC ¶ 61,017 (2006).

42. 2005 DOE Order at 5, 8–9.

43. Reliability Technical Conference, Docket No. AD12-1-000, *et al.*, Speaker Materials of Debra Raggio, GenOn Energy (filed Nov. 25, 2011), Attachment D, *Mirant Potomac River LLC*, Docket No. CAA-03-2006-0163DA, Administrative Compliance Order by Consent (June 1, 2006); EPA, Press Release, EPA Issues Administrative Order to Mirant Potomac River—Order Sets Schedule for Mirant to Comply with Clean Air Standards (June 2, 2006).

44. Reliability Technical Conference, Docket No. AD12-1-000, *et al.*, Speaker Materials of Debra Raggio, GenOn Energy (filed Nov. 25, 2011), Attachment D, *Mirant Potomac River LLC*, Docket No. CAA-03-2006-0163DA, Administrative Compliance Order by Consent at 14 (June 1, 2006).

45. *See* Reliability Technical Conference, Docket No. AD12-1-000, *et al.*, Speaker Materials of Debra Raggio, GenOn Energy at 5–6 (filed Nov. 25, 2011), Attachments E and F.

46. *See Notice of Issuance of Emergency Orders Under Section 202(c) of the Federal Power Act*, 65 Fed. Reg. 82,989 (Dec. 29, 2000); *see also* DOE Order, Order Pursuant to Section 202(c) of the Federal Power Act (Jan. 11, 2001).

47. *San Diego Gas & Elec. Co. v. Sellers of Energy & Ancillary Servs.*, 95 FERC ¶ 61,355 at 61,357 (2001). The must-offer obligation stemmed from an investigation into the reasonableness

of rates for the sale of electric energy in the CAISO and PX spot markets by FERC pursuant to its authority under Section 206 of the FPA.

48. *Id.*

49. *San Diego Gas & Elec. Co. v. Sellers of Energy & Ancillary Servs.*, 96 FERC ¶ 61,117 at 61,448 (2001) ("In sum, in order to be exempted from the must offer requirement, a generator must demonstrate that running its unit violates a permit, would result in a criminal or civil violation or penalties, or would result in QF units violating their contracts or losing their QF status. In lieu of submitting a presentation such as that filed by Mirant, a generator may obtain a declaratory order from an appropriate court finding that the generator's compliance with the must offer requirement will result in a violation of its permit.").

50. *See* Reliability Technical Conference, Docket No. AD12-1-000, *et al.*, Speaker Materials of Debra Raggio, GenOn Energy at 4 (filed Nov. 25, 2011).

51. 76 Fed. Reg. 48298 (August 8, 2011) (hereinafter "CSAPR").

52. CSAPR at 48,211.

53. Revisions to Federal Implementation Plans to Reduce Interstate Transport of Fine Particulate Matter and Ozone, 76 Fed. Reg. 63,860; Federal Implementation Plans for Iowa, Michigan, Missouri, Oklahoma, and Wisconsin and Determination for Kansas Regarding Interstate Transport of Ozone, Docket ID: EPA-HQ-OAR-2009-0491 (Dec. 17, 2011) (to be codified at 40 C.F.R. parts 52 and 97).

54. EPA, Cross-State Air Pollution Rule, Reducing Air Pollution Protecting Public Health, *presentation* (Dec. 15, 2011) (*at:* http://www.epa.gov/airtransport/pdfs/CSAPRPresentation.pdf).

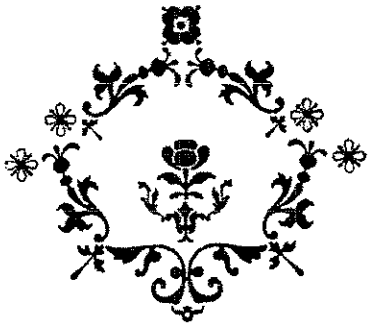
55. CSAPR at 48,279.

56. *See* EME Homer City Generation, L.P., *et al.* v. EPA, No. 11-1302 (D.C. Cir. Dec. 30, 2011) (order granting requested stay).

57. CSAPR at 48, 211.

58. National Emission Standards for Hazardous Air Pollutants from Coal and Oil fired Electric Utility Steam Generating Units, Docket ID EPA-HQ-OAR-2009-0234, pre-publication version, (*to be codified at* 40 C.F.R. Part 63) (hereinafter "MATS").

59. EPA FACT SHEET: Mercury and Air Toxics Standards, ADJUSTMENTS FROM PROPOSAL TO FINAL, Dec. 21, 2011; MATS at 630.



60. Comments of the Utility Air Research Group on EPA's National Emission Standards for Hazardous Air Pollutants from Coal and Oil-Fired Electricity Steam Generating Units, at 251, Docket EPA-HQ-OAR-2009-0234 (Aug. 4, 2011).

61. Study of Hazardous Air Pollutant Emissions from Electric Utility Steam Generating Units – Final Report to Congress, EPA, (Feb. 1998), *at:* http://www.epa.gov/ttn/atw/combust/utiltox/eurtc1.pdf.

62. *See* North American Electric Reliability Corporation, 2010 Special Reliability Scenario Assessment: Resource Adequacy of Potential U.S. Environmental Regulations (Oct. 2010), *at* http://www.nerc.com/files/EPA_Scenario_Final.pdf (hereinafter "NERC Report").

63. EPA FACT SHEET: Mercury and Air Toxics Standards, ADJUSTMENTS FROM PROPOSAL TO FINAL, Dec. 21, 2011.

64. MATS at 568.

65. *Id.*

66. *See* Memorandum for the Administrator of the Environmental Protection Agency, Flexible Implementation for the Mercury and Air Toxics Standards Rule, from Barack Obama (Dec. 21, 2011) (hereinafter "Presidential Memo"); Memorandum, The Environmental Protection Agency's Enforcement Response Policy For Use Of Clean Air Act Section 113(a) Administrative Orders In Relation To Electric Reliability And The Mercury And Air Toxics Standard, from Cynthia Giles (December 16, 2011) ("Enforcement Memo").

67. Presidential Memo at 2.

68. Fed. Reg. 35,128 (June 21, 2010).

69. Fed. Reg. 63,252 (Oct. 12, 2011).

70. EPA Eyes Late 2012 For Coal Ash Reuse Risk Analysis Ahead Of Final Rule, Inside EPA (Dec. 9, 2011) (quoting Administrator Jackson, "I think it's going to be towards the end of the year.").

71. Fed. Reg 43,230 (July 20, 2011).

72. See Settlement Agreement Among the United States Environmental Protection Agency, Plaintiffs in *Cronin, et al. v. Reilly*, 93 Civ. 314 (LTS(SDNY), and Plaintiffs in *Riverkeeper, et al. v. EPA*, 06 Civ. 12987 (PKC)(SDNY) (Nov. 22, 2010) as subsequently amended (available at: http://water.epa.gov/lawsregs/lawsguidance/cwa/316b/phase2/upload/316bsettlement.pdf).

73. Reliability Technical Conference, Docket No. AD12-1-000, *et al.*, PJM, Interconnection, L.L.C. Testimony of Mike Kormos at 3 (filed Nov. 22, 2011) (hereinafter "PJM Testimony").

74. *Id.* To date, PJM has not identified any "overarching reliability impacts associated with potentially retiring units that cannot be resolved with transmission upgrades within the four year period allowed by the proposed MATS rule." *Id.* at 8.

75. *See, e.g.*, NERC Report (finding 33-70 GW of coal-fired generation to be retired by 2015); *see also* Edison Electric Institute, Potential Impacts of Environmental Regulation on the U.S. Generation Fleet (Jan. 2011), *at* http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2011IRP/EEIModelingReportFinal-28January2011.pdf (finding 16-75 GW of unplanned coal-fired generation retirements by 2015) (hereinafter "EEI Report"); *Fitch: New EPA Rule Likely to Speed Plant Retirements*, WALL ST. J. (Dec. 23, 011) (citing Fitch Ratings, Time to Retire? II The Update to Coal Plant Retirements (Nov. 17, 2011)) (indicating up to 83 GW of coal-fired generation may be retired due to various EPA rules).

76. Joint Comments of the Electric Reliability Council of Texas, the Midwest Independent Transmission System Operator, the New York Independent System Operator, PJM Interconnection, LLC, and the Southwest Power Pool, Docket Nos. EPA-HQ-OAR-2009-0234, *et al.* (Oct. 21, 2011), *at* http://pjm.com/~/media/documents/other-fed-state/20110804-epa-hq-oar-2009-0234-iso-rto.ashx ("Joint RTO Comments").

77. *Id.* at 5.

78. *Id.* at 6.

79. *See* Enforcement Memo.

80. *See* Enforcement Memo; Presidential Memo.

81. Enforcement Memo at 5–6.

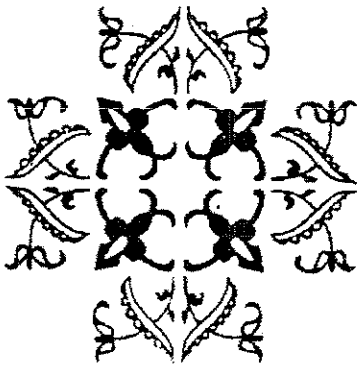
82. *Id.* at 6.

83. *See* Press Release, Sen. Murkowski (R-Alaska), Reliability Concerns Warrant Careful Review of Utility MACT Rule, (Dec. 21, 2011), *at* http://energy.senate.gov/public/index.cfm?FuseAction=PressReleases.Detail&PressRelease_id=821625c0-c4aa-4c79-8253-34a510a1bff6& Month=12&Year=2011&Party=1.

84. *See for example* Exelon Generation Company, LLC, Order Accepting and Suspending Tariff Filing at para. 30–31, 132 FERC ¶ 61,219 (Sep. 16, 2010).

85. *See, e.g., Blue Chip Stamps. v. Manor Drug Stores*, 421 U.S. 723 at 756 (1975) ("the starting point in every case involving construction of a statute is the language itself").

86. *See, e.g., Watt v. Alaska*, 451 U.S. 259, 267 (1981) (courts will read conflicting statutes "to give effect to each if [courts] can do so while preserving their sense and purpose"); *Morton v. Mancari*, 417 U.S. 535 at 550–551 (1974) ("the courts are not at liberty to pick and choose among congressional enactments, and when



two statutes are capable of co-existence, it is the duty of the courts, absent a clearly expressed congressional intention to the contrary, to regard each as effective").

87. *See, e.g., Nat'l Ass'n of Home Builders v. Defenders of Wildlife*, 551 U.S. 644, 661–669 (2007) (holding that the Endangered Species Act's "no-jeopardy duty only applies to discretionary agency actions and does not attach to actions . . . that an agency is *required* by statute to undertake once certain specified triggering events have occurred"); *Flint Ridge Dev. Co. v. Scenic Rivers Ass'n*, 426 U.S. 776 at 778 (1976) (where a clear and unavoidable conflict in statutory authority exists, "NEPA must give way"); *see also Operation of the Mo. River Syst. Litigation*, 421 F.3d 618, 630 (8th Cir. 2005) (stating that environmental statutes "do not apply where they would render an agency unable to fulfill a non-discretionary statutory purpose. . .").

88. *See Nat'l Wildlife Federation v. US Army Corps of Engineers*, 384 F.3d 1163, 1179 (9th Cir. 2004) (holding that the construction and operation of dams in accordance with Congressional mandates did not violate Clean Water Act provisions despite causing exceedances); *Platte River Whooping Crane Critical Habitat Maintenance Trust v. FERC*, 962 F.2d 27 (D.C. Cir. 1992) (holding that the Endangered Species Act does not alter the scope of FERC's authority under the FPA).

89. With respect to the Potomac River Generating Station, the VDEQ argued that the CAA and the FPA did not conflict because both DOE and FERC must consider and, if necessary, mitigate proposed actions under the National Environmental Policy Act (NEPA). Motion to Intervene and Protest of Virginia Department of Environmental Quality Director Robert G. Burnley, Docket No. EL05-145-000 (filed Aug. 29, 2005). However, this argument failed to take into account the fact that DOE orders issued in response to emergency situations are exempt from NEPA. *See* 10 C.F.R. 1021.343. Because DOE can only order a generating facility to operate in an emergency situation, NEPA will not apply.

90. *See Watt*, 451 U.S. at 266-67 (citing 2A C. Sands, Sutherland on Statutes and Statutory Construction Section 51.02 (4th ed. 1973)).

91. *Posadas v. National City Bank*, 296 U.S. 497, 503 (1936) ("the cardinal rule is that repeals by implication are not favored").

92. *See Bulova Watch Co. v. United States*, 365 U.S. 753, 758 ("it is familiar law that a specific statute controls over a general one 'without regard to priority of enactment'"); *see also* 2B Norman J. Singer, Sutherland Statutes and Statutory Construction Section 51.05 (6th ed. 2000).

93. *Morton*, 417 U.S. at 550–551 ("Where there is no clear intention otherwise, a specific statute will not be controlled or nullified by a general one, regardless of the priority of enactment.").

NERC
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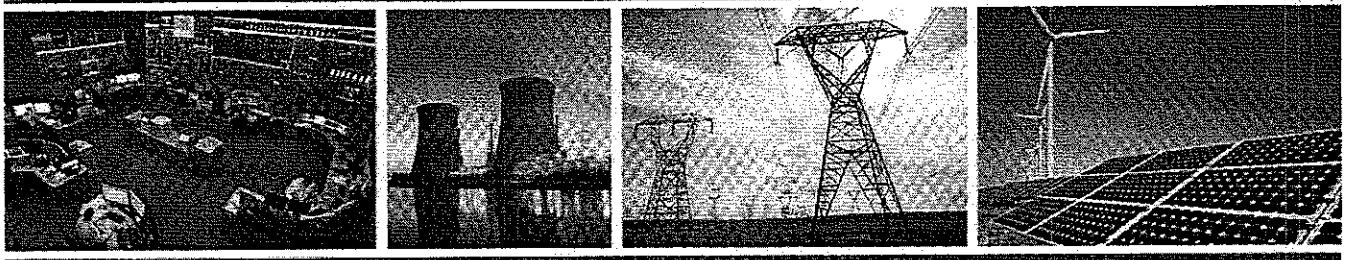
Polar Vortex Review

September 2014

RELIABILITY | ACCOUNTABILITY



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In Texas, ERCOT declared an Energy Emergency Alert[5] (EEA) Level 1 and then an EEA Level 2, primarily due to the loss of a number of generating units during the morning load ramp. They were able to recover within two hours and 11 minutes by deploying Non-Spin Reserve Service (NSRS), Responsive Reserve Service from generators, load resources, and Emergency Response Service (ERS).[6]

Two RCs that also experienced challenges were the VACS RC and PJM. In VACS RC, two BAs experienced difficulties when faced with the cold weather. The SCE&G BA experienced record electric demand the evening of January 6, 2014, and the morning of January 7, 2014. During that time, SCE&G lost more than 850 MW of generation from multiple sources. SCE&G addressed this loss of generation by following internal company procedures, which called for implementation of local and reserve-sharing group reserves, obtaining Emergency Assistance from neighbors and neighboring RCs, use of customer standby generators and curtailment of retail interruptible contract customers, appeals for conservation, distribution-level voltage reduction, and controlled firm load shed when reserves were not available for a period. All actions taken by SCE&G were intentional and in accordance with regulatory requirements.

Additionally, on January 7, the Duke Energy Progress (DEP) Carolina Power and Light East (CPLE) and Carolina Power and Light West (CPLW) BAs experienced all-time peak demand during the hour ending 8:00 a.m. Demand-side management resources, including an initial 2.9 percent system-wide voltage reduction, a large industrial load curtailment rider, general public appeal for conservation, and a water heater and strip heat control program, were deployed in the DEP TOP/BA footprint. As part of its General Load Reduction Plan, and while in a NERC Energy Emergency Alert Level 2, CPLE and CPLW BAs subsequently activated a 5 percent system-wide voltage reduction on the distribution system for their footprints at 7:54 a.m. Through the use of generation and demand-side management resources, the CPLE and CPLW BAs were able to serve an all-time peak demand without shedding firm load.

The second RC that experienced challenges was PJM. On January 3, they issued a Cold Weather Alert at approximately 11:00 a.m. for January 6–7. In addition, they successfully used emergency procedures and the EEA process to maintain their required level of reserves. Some of the actions taken included scheduling shared reserves from NYISO and ISO-NE, issuing EERs, using demand response, and initiating a 5 percent voltage reduction across a portion of their operating area.

Figure 5 illustrates the challenges experienced by System Operators with regard to generation capacity unavailability during the study period. The graph shows the cumulative amount of MW unavailable due to forced outages in the following five general categories:

- Unrelated – Outages not related to cold weather or the extremes presented by the polar vortex
- Unknown – Outages still under review to determine cause
- Miscellaneous – Outage types potentially related to extreme cold weather (e.g., opacity issues)
- Cold – Outages directly attributable to cold weather, including on-site fuel issues such as frozen coal piles, frozen equipment and/or sensors under the control of the generating plant, and gelled fuel
- Fuel – Outages that are directly related to the inability of the plant to receive fuel from their provider

[5] An Energy Emergency is a condition when a Load-Serving Entity has exhausted all other options and can no longer provide its customers' expected energy requirements.

[6] An emergency service consistent with P.U.C. SUBST. R. 25.507, Electric Reliability Council of Texas (ERCOT) Emergency Response Service (ERS), used during an Energy Emergency Alert (EEA) Level 2 to assist in maintaining or restoring ERCOT system frequency. ERS is not an Ancillary Service.

TITLE 16 - CONSERVATION
CHAPTER 12 - FEDERAL REGULATION AND DEVELOPMENT OF POWER
SUBCHAPTER II - REGULATION OF ELECTRIC UTILITY COMPANIES ENGAGED IN INTERSTATE COMMERCE

§ 824d. Rates and charges; schedules; suspension of new rates; automatic adjustment clauses

(a) Just and reasonable rates

All rates and charges made, demanded, or received by any public utility for or in connection with the transmission or sale of electric energy subject to the jurisdiction of the Commission, and all rules and regulations affecting or pertaining to such rates or charges shall be just and reasonable, and any such rate or charge that is not just and reasonable is hereby declared to be unlawful.

(b) Preference or advantage unlawful

No public utility shall, with respect to any transmission or sale subject to the jurisdiction of the Commission,

(1) make or grant any undue preference or advantage to any person or subject any person to any undue prejudice or disadvantage, or

(2) maintain any unreasonable difference in rates, charges, service, facilities, or in any other respect, either as between localities or as between classes of service.

(c) Schedules

Under such rules and regulations as the Commission may prescribe, every public utility shall file with the Commission, within such time and in such form as the Commission may designate, and shall keep open in convenient form and place for public inspection schedules showing all rates and charges for any transmission or sale subject to the jurisdiction of the Commission, and the classifications, practices, and regulations affecting such rates and charges, together with all contracts which in any manner affect or relate to such rates, charges, classifications, and services.

(d) Notice required for rate changes

Unless the Commission otherwise orders, no change shall be made by any public utility in any such rate, charge, classification, or service, or in any rule, regulation, or contract relating thereto, except after sixty days' notice to the Commission and to the public. Such notice shall be given by filing with the Commission and keeping open for public inspection new schedules stating plainly the change or changes to be made in the schedule or schedules then in force and the time when the change or changes will go into effect. The Commission, for good cause shown, may allow changes to take effect without requiring the sixty days' notice herein provided for by an order specifying the changes so to be made and the time when they shall take effect and the manner in which they shall be filed and published.

(e) Suspension of new rates; hearings; five-month period

Whenever any such new schedule is filed the Commission shall have authority, either upon complaint or upon its own initiative without complaint, at once, and, if it so orders, without answer or formal pleading by the public utility, but upon reasonable notice, to enter upon a hearing concerning the lawfulness of such rate, charge, classification, or service; and, pending such hearing and the decision thereon, the Commission, upon filing with such schedules and delivering to the public utility affected thereby a statement in writing of its reasons for such suspension, may suspend the operation of such schedule and defer the use of such rate, charge, classification, or service, but not for a longer period than five months beyond the time when it would otherwise go into effect; and after full hearings, either completed before or after the rate, charge, classification, or service goes into effect, the Commission may make such orders with reference thereto as would be proper in a proceeding initiated after it had become effective. If the proceeding has not been concluded and an order made at the expiration of such five months, the proposed change of rate, charge, classification, or service shall go into effect at the end of such

period, but in case of a proposed increased rate or charge, the Commission may by order require the interested public utility or public utilities to keep accurate account in detail of all amounts received by reason of such increase, specifying by whom and in whose behalf such amounts are paid, and upon completion of the hearing and decision may by further order require such public utility or public utilities to refund, with interest, to the persons in whose behalf such amounts were paid, such portion of such increased rates or charges as by its decision shall be found not justified. At any hearing involving a rate or charge sought to be increased, the burden of proof to show that the increased rate or charge is just and reasonable shall be upon the public utility, and the Commission shall give to the hearing and decision of such questions preference over other questions pending before it and decide the same as speedily as possible.

(f) Review of automatic adjustment clauses and public utility practices; action by Commission; "automatic adjustment clause" defined

(1) Not later than 2 years after November 9, 1978, and not less often than every 4 years thereafter, the Commission shall make a thorough review of automatic adjustment clauses in public utility rate schedules to examine—

(A) whether or not each such clause effectively provides incentives for efficient use of resources (including economical purchase and use of fuel and electric energy), and

(B) whether any such clause reflects any costs other than costs which are—

(i) subject to periodic fluctuations and

(ii) not susceptible to precise determinations in rate cases prior to the time such costs are incurred.

Such review may take place in individual rate proceedings or in generic or other separate proceedings applicable to one or more utilities.

(2) Not less frequently than every 2 years, in rate proceedings or in generic or other separate proceedings, the Commission shall review, with respect to each public utility, practices under any automatic adjustment clauses of such utility to insure efficient use of resources (including economical purchase and use of fuel and electric energy) under such clauses.

(3) The Commission may, on its own motion or upon complaint, after an opportunity for an evidentiary hearing, order a public utility to—

(A) modify the terms and provisions of any automatic adjustment clause, or

(B) cease any practice in connection with the clause,

if such clause or practice does not result in the economical purchase and use of fuel, electric energy, or other items, the cost of which is included in any rate schedule under an automatic adjustment clause.

(4) As used in this subsection, the term "automatic adjustment clause" means a provision of a rate schedule which provides for increases or decreases (or both), without prior hearing, in rates reflecting increases or decreases (or both) in costs incurred by an electric utility. Such term does not include any rate which takes effect subject to refund and subject to a later determination of the appropriate amount of such rate.

(June 10, 1920, ch. 285, pt. II, § 205, as added Aug. 26, 1935, ch. 687, title II, § 213, 49 Stat. 851; amended Pub. L. 95–617, title II, §§ 207(a), 208, Nov. 9, 1978, 92 Stat. 3142.)

Amendments

1978—Subsec. (d). Pub. L. 95–617, § 207(a), substituted "sixty" for "thirty" in two places.

Subsec. (f). Pub. L. 95–617, § 208, added subsec. (f).

NB: This unofficial compilation of the U.S. Code is current as of Jan. 4, 2012 (see http://www.law.cornell.edu/uscode/uscprint.html).

Study of Electric Rate Increases Under Federal Power Act

Section 207(b) of Pub. L. 95–617 directed chairman of Federal Energy Regulatory Commission, in consultation with Secretary, to conduct a study of legal requirements and administrative procedures involved in consideration and resolution of proposed wholesale electric rate increases under Federal Power Act, section 791a et seq. of this title, for purposes of providing for expeditious handling of hearings consistent with due process, preventing imposition of successive rate increases before they have been determined by Commission to be just and reasonable and otherwise lawful, and improving procedures designed to prohibit anticompetitive or unreasonable differences in wholesale and retail rates, or both, and that chairman report to Congress within nine months from Nov. 9, 1978, on results of study, on administrative actions taken as a result of this study, and on any recommendations for changes in existing law that will aid purposes of this section.

Appendix B:21 365 U.S. 753 (1961)

Search

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Bulova Watch Co., Inc. v. United States
365 U.S. 753 (1961)

Annotate this Case

Syllabus | Case

U.S. Supreme Court

Bulova Watch Co., Inc. v. United States, 365 U.S. 753 (1961)

Bulova Watch Co., Inc. v. United States

No. 241

Argued March 27, 1961

Decided April 17, 1961

365 U.S. 753

CERTIORARI TO THE COURT OF CLAIMS

Syllabus

When the Court of Claims has awarded a judgment against the United States to a taxpayer for an overpayment of excess profits taxes, plus interest thereon "as provided by law," determination of the allowance of interest on so much of the overpayment as was attributable to an unused excess profits credit carry-back is governed by § 3771(e)

of the Internal Revenue Code of 1939, dealing specifically with interest on overpayments resulting from carry-backs, rather than by 28 U.S.C. § 2411(a), relating to interest on judgments for tax overpayments generally. Pp. 365 U. S. 753-761.

Affirmed.

MR. JUSTICE WHITTAKER delivered the opinion of the Court.

Petitioner recovered a judgment in the Court of Claims against the United States for an overpayment of its excess profits taxes for the fiscal year ended March 31, 1942, in the amount of $211,899.28, plus interest thereon "as provided by law." 163 F.Supp. 633, 637, 143 Ct.Cl. 342. Of the principal sum of the judgment, $150,016.21 was attributable to an unused excess profits credit carry-back from the succeeding year ended March 31, 1943.

Page 365 U. S. 754

Acting in accordance with the provisions of § 3771(e) of the Internal Revenue Code of 1939, the Commissioner computed and allowed statutory interest on the latter sum from June 14, 1945, the date on which petitioner filed its claim for refund, to April 25, 1959 -- 30 days prior to issuance of the refund check -- in the amount of $124,784.72. Thereafter, petitioner moved the Court of Claims for relief from the Commissioner's interpretation of the judgment, contending that interest should be computed, under the provisions of 28 U.S.C. § 2411(a), from the earliest date the overpayment could have been determined (the end of the fiscal year subsequent to the year involved, *i.e.,* March 31, 1943), rather than from the date it filed its claim for refund (June 14, 1945) as provided in § 3771(e), and that it was thus entitled to the further sum of $51,252.69. The motion was denied, without opinion.

Because of the importance of the question involved to the proper administration of the internal revenue laws, and to settle a conflict between the lower federal courts upon the question, [Footnote 1] we granted certiorari. 364 U.S. 861.

The question thus presented is whether the date from which interest accrues on an overpayment of taxes attributable to an unused excess profits credit carry-back is governed by § 3771(e) [Footnote 2] of the Internal Revenue Code of 1939, or by 28 U.S.C. § 2411(a). [Footnote 3]

Page 365 U. S. 755

Petitioner contends that, because refund of the tax was not awarded administratively, but by the "judgment of (a) court," the date from which interest runs is governed by the provisions of § 2411(a), and that it is thus entitled to interest from "the date of the payment" on the "overpayment" which, it argues, became ascertainable,

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and hence should be regarded as made, on March 31, 1943. [Footnote 4] The Government, on the other hand, contends that § 3771(e) is a special statute relating exclusively to tax refunds attributable to the carry-back provisions of the internal revenue laws, and hence prevails, as respects the special subject of carry-backs, over the general provisions of § 2411(a). After a careful review of these and other statutes and their legislative history, we have concluded that the Government is right.

Section 3771(e) of the 1939 Code deals specifically with the subject of interest on tax refunds attributable to the carry-back of a net operating loss or an unused excess profits tax credit, and is "an integral part of the carry-back provision[s]" of the internal revenue laws. *Manning v. Seeley Tube & Box Co.,* 338 U. S. 561, 338 U. S. 568. It specifically says that,

"[i]f the Commissioner determines that any part of an overpayment is attributable to . . . [an] unused excess profits credit for a succeeding taxable year, no interest shall be allowed or paid with respect to such part of the overpayment for any period before the filing of a claim for credit or refund of such part of the overpayment or the filing of a petition with the Tax Court, whichever is earlier."

The refund awarded here was solely "attributable to . . . [an] unused excess profits credit for [the] succeeding taxable year." How, then, can petitioner be entitled to interest "for any period before the filing of a claim for credit or refund"?

Page 365 U. S. 757

Petitioner agrees that if its award had been made administratively by the Commissioner or the Tax Court, [Footnote 5] rather than by the "judgment" of the Court of Claims, interest would not be allowable on the refund for any period prior to the filing of its claim. But it argues that the language of § 2411(a) --

"In any judgment of any court rendered . . . for any overpayment in respect of any internal revenue tax, interest shall be allowed . . . upon the amount of the overpayment, from the date of the payment or collection thereof [Footnote 6]"

-- requires the allowance of interest "from the date of the payment or collection" of the tax when recovery is awarded by a District Court or, as here, by the Court of Claims. The effect of petitioner's contention thus is that Congress has made the starting date of interest in such cases dependent upon the forum selected by the taxpayer. Its argument would mean -- in fact, it frankly proceeds on the theory -- that a taxpayer, holding a refund claim attributable to an unused excess profits credit, could, by proceeding in a District Court or the Court of Claims, recover interest from the date when a claim for refund could have been filed, yet, if he proceeded through the Tax Court, he could not recover interest for any period prior to the actual filing of his claim, even though the Tax Court's final judgments (or orders) are subject to review by the United States Courts of Appeals, and ultimately by this Court. In the light of the provisions of § 3771(e) and its legislative history, it is almost certain that Congress did not intend such an anomalous, nonuniform and discriminatory result.

Page 365 U. S. 758

Petitioner further contends that § 2411(a) is a later enactment than § 3771(e), and, for that reason, should take precedence over it. We do not believe that § 2411(a) can fairly be regarded as a later enactment than § 3771(e), for, at the time § 3771(e) was enacted in 1942, a predecessor provision of § 2411(a) had long been on the books. Save for the word "hereby" -- of no possible significance -- that predecessor provision (§ 177(b) of the Judicial Code, 28 U.S.C. (1940 ed.) § 284(b)) was identical with the present § 2411(a). [Footnote 7] But even if petitioner were correct in concluding that § 2411(a) is to be regarded as the later enactment, it would not necessarily take precedence over § 3711 (e), for it is familiar law that a specific statute controls over a general one "without regard to priority of enactment." *Townsend v. Little,* 109 U. S. 504, 109 U. S. 512. *See e.g., Ginsberg & Sons v. Popkin,* 285 U. S. 204, 285 U. S. 208; *MacEvoy Co. v. United States,* 322 U. S. 102, 322 U. S. 107; *Fourco Glass Co. v. Transmirra Products Corp.*, 353 U. S. 222, 353 U. S. 228-229.

Section 3771(e) specifically fixes the date from which interest shall run on carry-back refunds. It came into the law with the Revenue Act of 1942, which authorized carry-backs. A carry-back is an exceptional relief measure

Page 365 U. S. 759

in that it permits a departure from the basic annual accounting rule. The carry-back provisions

"were enacted to ameliorate the unduly drastic consequences of taxing income strictly on an annual basis. They were designed to permit a taxpayer to set off its lean years against its lush years, and to strike something like an average taxable income computed over a period longer than one year."

Libson Shops, Inc. v. Koehler, 353 U. S. 382, 353 U. S. 386.

The significant feature of a carry-back is that it permits an adjustment of an earlier liability upon the basis of subsequent events. It contemplates that the initial tax obligation was not incorrectly or mistakenly imposed but was actually due, but that an adjustment may be made upon the basis of the taxpayer's gain or loss in the succeeding year or years, and it is evident from the very terms of § 3771(e) that Congress thought it would be unfair to the Government to require it to pay interest on a claim brought about by such a retroactive adjustment prior to the time when the taxpayer took affirmative steps to bring home to the Commissioner that he is now in position to claim, and claims, a readjustment of his past admittedly correct tax liability. Section 3771(e) does not, of course, deny interest on carry-back refunds. It only prohibits the accrual of interest prior to the time the taxpayer's claim therefor is filed with, and thus made known to, the Commissioner.

The report of the Senate Finance Committee on the bill that became § 3771(e) clearly discloses that these were Congress' purposes in adopting the section. It said:

"A taxpayer entitled to a carry-back of a net operating loss or an unused excess profits credit (*see* sec. 204 of the bill) will not be able to determine the deduction on account of such carry-back until the close of the future taxable year in which he sustains the net operating loss or has the unused excess profits credit. He must therefore file his return and pay his tax without regard to such deduction, and must file a claim for refund at the close of the succeeding taxable year when he is able to determine the amount of such carry-back. Inasmuch as any overpayment resulting from the deduction of such carry-back does not occur, as a practical matter, until the net operating loss or the unused excess

Page 365 U. S. 760

profits credit for the future taxable year is determined, and inasmuch as it is desirable to insure promptness in the filing of claims to inform the Commissioner that such deductions have been determined, this section provides *that no interest will be allowed with respect to any such overpayment for any period before the claim therefor is filed,* or a petition asserting such overpayment is filed with the Board of Tax Appeals, whichever is earlier. [Footnote 8]"

(Emphasis added.) This surely shows Congress' purpose to deny interest on carry-back refunds for any period prior to the time they could be determined, and also to prevent, through delay in the presentation of claims, the accumulation of interest after that date and prior to the filing of the claim. [Footnote 9]

In providing, in § 6611(f) of the 1954 Internal Revenue Code, that overpayments resulting from the carry-back of net operating losses "shall be deemed not to have been made prior to the close of the taxable year in which such net operating loss arises," Congress recognized that

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it was making a change from existing law. The relevant Committee Report [Footnote 10] makes this clear. It said, in pertinent part, that:

"Existing law denies interest on an overpayment caused by a carry-back for any period prior to the filing of a claim for credit or refund of such amount (or filing a petition with the Tax Court with respect to such amount). Under this [proposed] section, interest is denied only for the period prior to the close of the taxable year in which the net operating loss arises. This is consistent with the rule for interest on underpayments (*see* the discussion of sec. 6601). [Footnote 11]"

In the light of the provisions of § 3771(e) and its clear legislative history, we think it is a special statute relating solely to, and exclusively governing, tax refunds attributable to the carry-back provisions of the internal revenue laws, and hence prevails, as respects the special subject of carry-backs, over the general provisions of § 2411(a). The judgment of the Court of Claims was therefore correct and must be affirmed.

Affirmed.

MR. JUSTICE DOUGLAS dissents.

[Footnote 1]

In *Carter v. Liquid Carbonic Pacific Corp.*, 97 F.2d 1, the Court of Appeals for the Ninth Circuit reached a result contrary to that reached by the Court of Claims in this case.

[Footnote 2]

Internal Revenue Code of 1939:

"§ 3771. Interest on Overpayments."

"(a) *Rate.* -- Interest shall be allowed and paid upon any overpayment in respect of any internal revenue tax at the rate of 6 percentum per annum."

"(b) *Period.* -- Such interest shall be allowed and paid as follows:"

"(1) *Credits.* -- In the case of a credit. . . ."

"(2) *Refunds.* -- In the case of a refund, from the date of the overpayment to a date preceding the date of the refund check by not more than thirty days. . . ."

"* * * *"

"(e) [as added by § 153(d), Revenue Act of 1942, c. 619, 56 Stat. 798, 847] *Claims based on carry-back of loss or credit.* -- If the Commissioner determines that any part of an overpayment is attributable to the inclusion in computing the net operating loss deduction for the taxable year of any part of the net operating loss for a succeeding taxable year or to the inclusion in computing the unused excess profits credit adjustment for the taxable year of any part of the unused excess profits credit for a succeeding taxable year, no interest shall be allowed or paid with respect to such part of the overpayment for any period before the filing of a claim for credit or refund of such part of the overpayment or the filing of a petition with the Tax Court, whichever is earlier."

[Footnote 3]

28 U.S.C.:

"§ 2411 [as amended by § 120, Act of May 24, 1949, c. 139, 63 Stat. 89, 106]. *Interest.*"

"(a) In any judgment of any court rendered (whether against the United States, a collector or deputy collector of internal revenue, a former collector or deputy collector, or the personal representative in case of death) for any overpayment in respect of any internal revenue tax, interest shall be allowed at the rate of 6 percentum per annum upon the amount of the overpayment, from the date of the payment or collection thereof to a date preceding the date of the refund check by not more than thirty days, such date to be determined by the Commissioner of Internal Revenue. The Commissioner is authorized to tender by check payment of any such judgment, with interest as herein provided at any time after such judgment becomes final, whether or not a claim for such payment has been duly filed, and such tender shall stop the running of interest, whether or not such refund check is accepted by the judgment creditor."

[Footnote 4]

It will be noted that petitioner stops short of claiming that it is entitled to interest from the date it paid its 1942 excess profits tax. It claims, rather, that interest runs from the end of the succeeding tax year that gave rise to the carry-back (*i.e.*, March 31, 1943). The Government's position, on the other hand, is that the interest runs from June 14, 1945, the date on which the refund claim was first presented.

[Footnote 5]

Petitioner points to the fact that, in *Lasky v. Commissioner,* 352 U.S. 1027, the Tax Court was held to be an administrative agency.

[Footnote 6]

Petitioner does not in fact claim interest from the date it actually paid its excess profits taxes for the year 1942 but, rather, from the end of the succeeding tax year that gave rise to the carry-back, *i.e.,* March 31, 1943. *See*note 4

[Footnote 7]

The history of 28 U.S.C. § 2411(a) and its predecessor provisions goes back to 1911. *See* § 177(b) of the Judicial Code, enacted in 1911 (c. 231, 36 Stat. 1141), as amended by the Revenue Act of 1921 (c. 136, 42 Stat. 227, § 1324(b)), as further amended by the Revenue Act of 1926 (c. 27, 44 Stat. 9, § 1117). Further amendments occurred in 1928 (45 Stat. 791, § 615) and in 1936 (49 Stat. 1648, § 808). The 1948 codification omitted from the Judicial Code all reference to interest on tax overpayments, but, by a correction Act in 1949 (c. 139, 63 Stat. 89, § 120), Congress restored the section to the Judicial Code as § 2411(a). The only difference between § 177(b) as it stood in 1942, and § 2411 (a) as it stands today, is that the word "hereby" no longer appears. Thus, § 3771(e) is not only the specific enactment designed to control the subject of interest in carry-back cases, but it is also a later enactment than § 2411(a).

[Footnote 8]

S.Rep. No. 1631, 77th Cong., 2d Sess., pp. 123-124.

[Footnote 9]

That Congress did not propose to allow interest for any period prior to presentment of the claim is further confirmed by the provisions of § 6 of the Tax Adjustment Act of 1945, c.

340, 59 Stat. 517, amending § 3771(e). Section 4 of that Act added a new section to the Internal Revenue Code, § 3780, providing for tentative carry-back adjustments. The concurrent amendment of § 3771(e) specifies that interest shall not start to run prior to the date application is made for the tentative carry-back adjustments.

[Footnote 10]

H.R.Rep. No. 1337, 83d Cong., 2d Sess, p. A418.

[Footnote 11]

Section 6601(e) provides that if the amount of tax is reduced by a carry-back loss, the reduction shall not affect the interest payable thereon by the taxpayer for the period ending with the close of the year in which the loss arises. Section 292(c) of the 1939 Code (added by § 6 of the Tax Adjustment Act of 1945, c. 340, 59 Stat. 517) provided:

"If any part of a deficiency is determined by the Commissioner to be attributable . . . to a carry-back to which an overpayment described in section 3771(e) . . . in any other tax is attributable . . . no interest shall be assessed or paid under subsection (a) [providing that interest is payable on a deficiency from the date prescribed for the payment of the tax] with respect to such part of the deficiency for any period during which interest was not allowed with respect to such overpayment. . . ."

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Where does Ohio's electricity come from?

In Ohio, the majority of our electricity is generated using nonrenewable resources like coal, natural gas, nuclear and petroleum. While these resources are found naturally in the earth and produce large amounts of electricity, nonrenewable resources take a long time to form, and there is a limited supply available for people to use for power generation.

Renewable resources including hydropower, wind, biomass and solar energy are also used to produce electricity, but often on a smaller scale. These resources are readily available in nature and can be replenished relatively quickly.

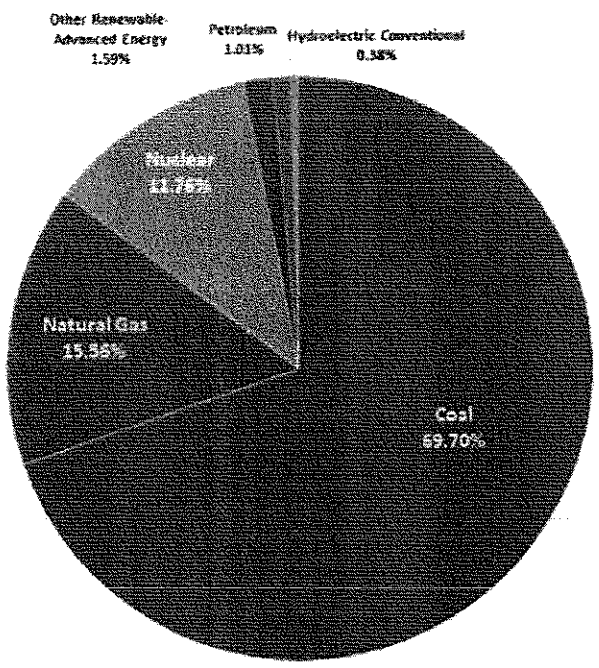
The PUCO supports a mix of generation resources in order to minimize the risks, including price spikes, associated with an exclusive reliance on any one type of electric generation. Below are brief descriptions of the generation resources currently used in Ohio.

Coal, a nonrenewable fossil fuel, is used to generate 69.7 percent of the electricity in Ohio. Coal is burned to produce heat, which converts water into high-pressure steam. The steam turns the blades of a turbine that is connected to a generator. The generator spins and converts mechanical energy to electricity.

Natural gas, a nonrenewable fossil fuel, can either be burned to produce steam or to produce hot combustion gas that passes through the turbine blades. Approximately 15.56 percent of the electricity in Ohio is produced using natural gas and other gases.

Petroleum, a nonrenewable fossil fuel, is burned to create steam to turn the turbine blades. The most common form of petroleum used to make electricity is fuel oil, a type of oil that is refined from crude oil. Petroleum generates approximately one percent of Ohio electricity.

Ohio generation output 2013



Source: EIA Jan-Nov '13

Nuclear power involves a process called fission in which the atoms of the element uranium split, releasing heat to turn water into steam and rotate the turbine blades. Nuclear power is nonrenewable and is used to generate about 11.76 percent of Ohio electricity.

In **hydropower** generation, flowing water is used to spin the turbine connected to the generator. Hydropower plants can use the current from a river or falling water that has accumulated in a dam to create the force needed to turn the turbine blades.

Wind turbines harness the force of the natural wind to turn the generator turbine.

Solar power uses photovoltaic cells to harness the energy of the sun to produce energy.

Geothermal energy involves the heat buried beneath the surface of the earth. This heat transforms water into steam, which is then tapped to be used at steam-turbine plants.

Biomass energy resources include wood and wood wastes, landfill gas, biogas from food processing waste, animal waste, sewage sludge, and potential energy crops. The **Ohio Biomass Energy Program** (OBEP) works to promote the use of biomass in Ohio.

Snapshot of existing and planned renewable energy facilities in Ohio

Wind

- Timber Road Wind Farm II, 55 turbines, 100 MW*
- Blue Creek Wind Farm, 160 turbines, 350 MW*
- Northwest Ohio Wind, 59 turbines, 100 MW**
- Buckeye Wind Farm, 54 turbines, 135 MW***
- Buckeye II Wind Farm, 56 turbines, 140 MW***
- Hardin Wind Farm, 132 turbines, 211 MW***
- Hog Creek Wind Farm I & II, 43 turbines, 67 MW***
- Timber Road Wind Farm I & III, 60 turbines, 99 MW***
- Black Fork, 91 turbines, 200 MW***
- Scioto Ridge, 176 turbines, 300 MW***

* Operational
**Under construction
***Approved (not yet under construction)

More information on wind

Solar

- Wyandot Solar Energy Generation Facility, 12 MW
- BNB Napoleon Solar, 9.8 MW
- First Solar Perrysburg Array, 2.4 MW
- Bryan Municipal Utilities, 2 MW
- Melink Solar Canopy at the Cincinnati Zoo, 1.6 MW
- Yankee Station Solar Generating Facility, 1.1 MW
- Centerburg High School Solar Array, 1 MW

Hydro and Other

- 130 MW hydroelectric capacity statewide
- 19 landfill gas projects of which nine generate electricity for a total capacity of 50 MW
- Biomass generation using waste residue to generate heat and power onsite in the wood manufacturing and paper industries

Ohio's renewable energy portfolio standard

Ohio law contains an alternative energy portfolio standard that requires that 12.5 percent of electricity sold by Ohio's electric distribution utilities or electric services companies must be generated from renewable energy sources by 2027

The law sets annual benchmarks, or incremental percentage requirements for renewable energy, through 2027. Each utility and electric services company is subject to compliance payments if the annual benchmarks are not met. Utilities and electric services companies may purchase renewable energy credits to meet the renewable energy standard.

services being provided at rates, terms and conditions that are just and reasonable and not unduly discriminatory or preferential.

14. The Commission appreciates the significant work that will go into the preparation of compliance proposals in response to this Final Rule. To assist public utility transmission providers in their efforts to comply, the Commission directs its staff to hold informational conferences within 60 days of the effective date of this Final Rule to review and discuss the requirements imposed herein with interested parties. Moreover, as public utility transmission providers work with their stakeholders to prepare compliance proposals, the Commission encourages frequent dialogue with Commission staff to explore issues that are specific to each transmission planning region. The Commission will monitor progress being made.

A. Order Nos. 888 and 890

15. In Order No. 888,[7] issued in 1996, the Commission found that it was in the economic interest of transmission providers to deny transmission service or to offer transmission service to others on a basis that is inferior to that which they provide to

[7] *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Order No. 888, 61 FR 21540 (May 10, 1996), FERC Stats. & Regs. ¶ 31,036 (1996), *order on reh'g*, Order No. 888-A, 62 FR 12274 (Mar. 14, 1997), FERC Stats. & Regs. ¶ 31,048, *order on reh'g*, Order No. 888-B, 81 FERC ¶ 61,248 (1997), *order on reh'g*, Order No. 888-C, 82 FERC ¶ 61,046 (1998), *aff'd in relevant part sub nom. Transmission Access Policy Study Group v. FERC*, 225 F.3d 667 (D.C. Cir. 2000), *aff'd sub nom. New York v. FERC*, 535 U.S. 1 (2002).

overcoming hurdles to developing the nation's vast renewable energy resources and providing clean energy jobs. National Grid contends that the creation of a robust transmission system is imperative to achieving important policy goals, environmental objectives, market efficiencies, and the integration of renewable and distributed resources into electric power markets.

35. NextEra agrees on reply that there is a need for generic reform at this time, stating that there is a sufficient basis for the Commission to proceed with a rulemaking proceeding and that there is ample evidence of the pressing need to enhance the transmission grid. NextEra states that the Proposed Rule demonstrates how and why existing transmission planning and cost allocation rules are inadequate.

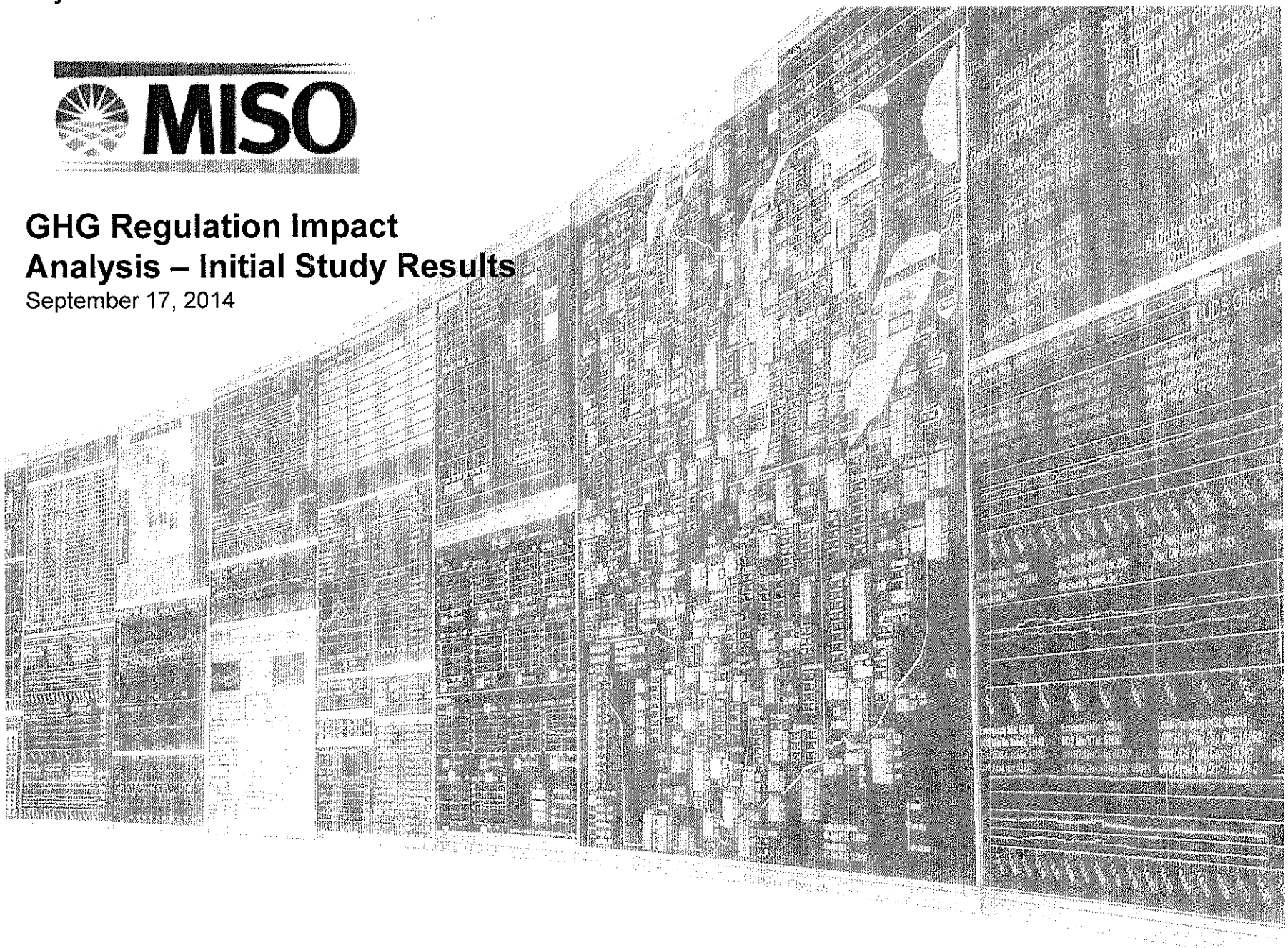
36. A number of commenters provide specific examples of developments that further demonstrate the need for reform. Colorado Independent Energy Association states that, in WestConnect, regional transmission providers are not ignoring the problem of transmission constraints, but that development of transmission facilities is not being undertaken and, second, transmission facilities are not being properly sized. In its view, the problems can be traced to the absence of cost allocation methods or the lack of means for identifying the most needed projects and pursuing them to completion.

37. Iberdrola Renewables contends that the lack of transmission expansion in the MISO has led to significant congestion in areas with extensive operating wind generation. It states that the MISO has reported that wind curtailments primarily caused

participants."

425. Other commenters offer specific suggestions as to the design and implementation of interregional coordination procedures. Minnesota PUC and Minnesota Office of Energy Security argue that, for the studies of an entire project to be meaningful and informative, all transmission planning entities studying a project should be required to coordinate their information and studies. Pioneer Transmission recommends that the Commission require planning regions to evaluate interregional projects through a single, coordinated process. It believes that if projects are studied under separate procedures by each planning region, interregional coordination would be unnecessarily delayed and more expensive than if the project was studied under a single set of procedures. However, Connecticut & Rhode Island Commissions contend that the Commission should require that proposed interregional projects be independently processed through each applicable regional planning process before they are eligible for joint evaluation through interregional coordination procedures.

426. Old Dominion similarly recommends that coordinated analysis of interregional transmission facilities be accomplished through preliminary evaluation within existing regional transmission planning processes, followed by an evaluation of the project on an interregional basis. If the identified transmission facility is determined to meet interregional needs, the relevant transmission planning regions would incorporate the project into their regional transmission planning processes and further assess its effects

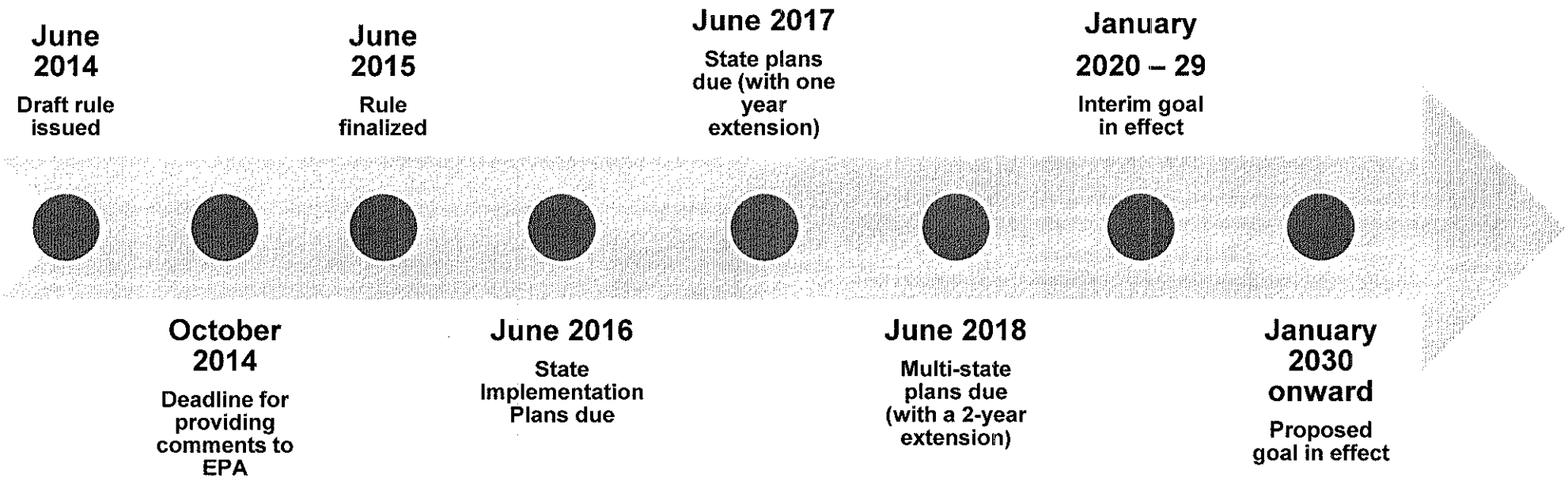


GHG Regulation Impact Analysis – Initial Study Results

September 17, 2014

The purpose of MISO's analysis…

…is to inform stakeholders of potential impacts on the generation fleet and load resulting from the EPA's proposal to reduce CO_2 emissions from existing electric generating units.



Study objectives and key takeaways

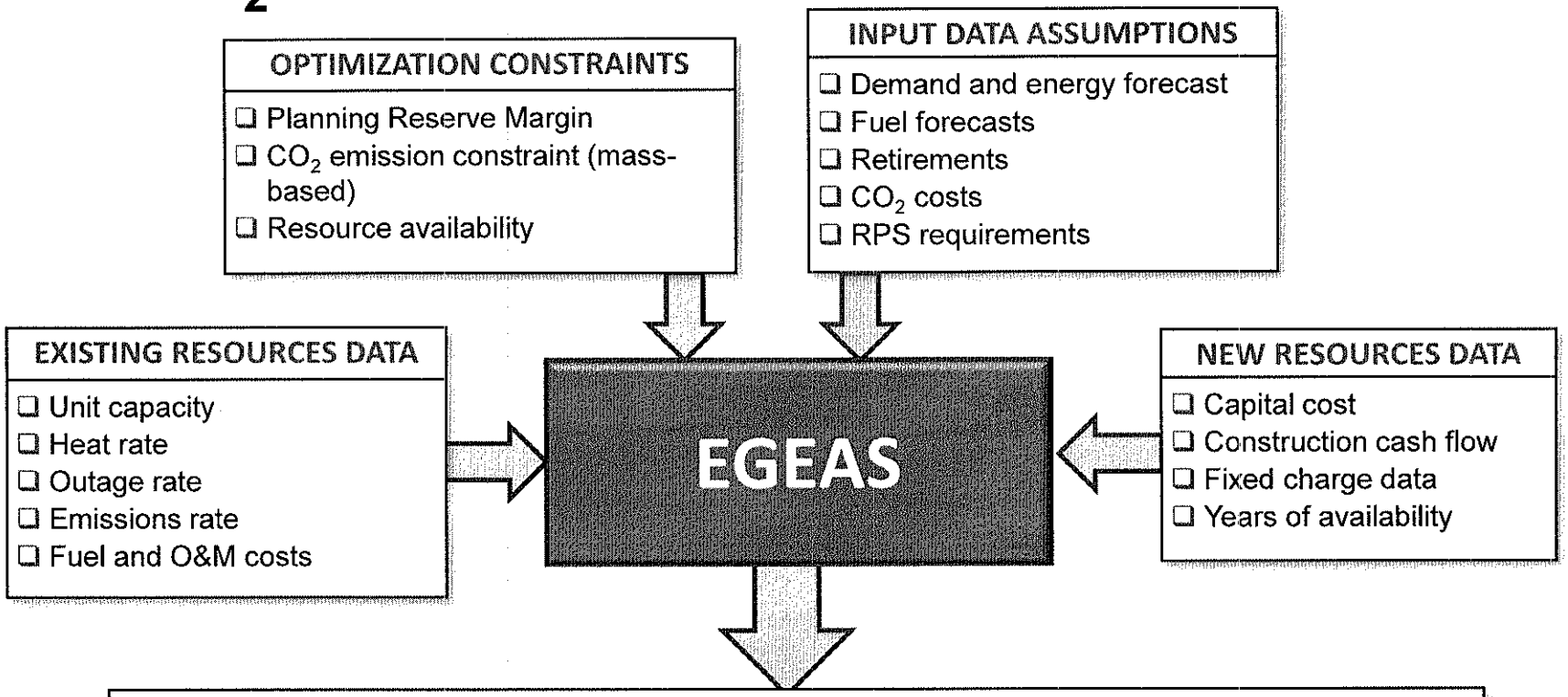
Study Phase	Objectives	Study results indicate that…
Phase 1	Calculation of the compliance costs for regional (MISO footprint) and sub-regional (Local Resource Zones) CO_2 management ➢ Applying the Building Blocks as proposed in the EPA's draft rule ➢ Applying a regional CO_2 constraint, i.e., a regional CO_2 reduction target	**Alternative compliance options outside the building blocks could achieve the proposed level of CO_2 reduction at a lower cost.** **Regional compliance options save approximately $3B annually** compared to sub-regional compliance.
Phase 2	Examination of the range of CO_2 emissions reductions, and associated costs, under various future policy and economic assumptions	**Up to an additional 14GW of coal capacity could be at-risk for retirement.**

Each state has a proposed state-wide CO_2 emissions rate goal calculated as:

$$\text{Rate (lbs/MWh)} = \frac{\textit{Statewide } CO_2 \textit{ emissions from covered fossil fuel-fired power plants (lbs)}}{\textit{State electricity generation from covered fossil plants + renewable energy + nuclear (at-risk portion and New) + energy efficiency (EE) (MWh)}}$$

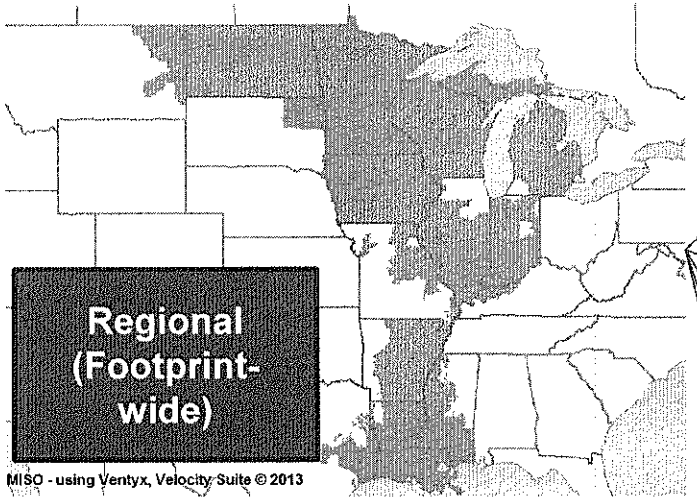
- Numerator – sum of CO_2 emissions from existing generating units
- Denominator – electricity generation in the state excludes existing hydro and new thermal resources
- Every state is assigned a different proposed rate goal (lbs/MWh) for the interim (2020-2029) and the final (2030 onward) periods
- For modeling purposes, rate-to-MISO-equivalent mass was calculated:
  - Emissions in tons = (qualifying 2012 system generation + renewable and EE mandate-driven energy forecast) * (proposed CO_2 emission rate goal for a state)
  - Only the MISO portion of the state was modeled

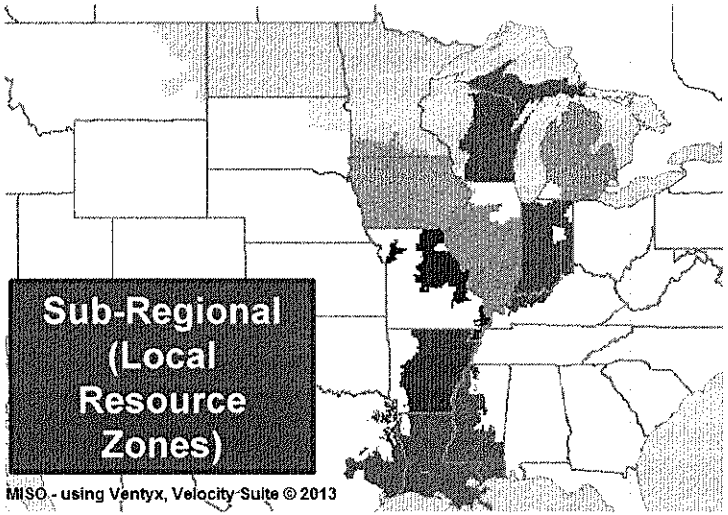
EGEAS was used to study potential impacts of the draft CO_2 emissions reduction rule



Total System Costs = Sum of Production Cost + Fixed O&M Cost + Capital Carrying Costs.

Phase 1 : An assessment of EPA's Building Blocks





- Building Block 1
  - Cost of Compliance
  - Emissions Reduction Achieved
- Building Block 2
  - Cost of Compliance
  - Emissions Reduction Achieved
- Building Block 3
  - Cost of Compliance
  - Emissions Reduction Achieved
- Building Block 4
  - Cost of Compliance
  - Emissions Reduction Achieved
- All Building Blocks
  - Cost of Compliance
  - Emissions Reduction Achieved

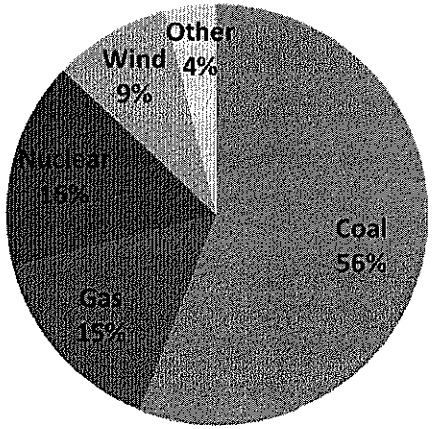
Reference case & Phase 1 scenarios

Scenario	EPA Assumptions and Methodology	Cost per ton of CO_2 reduction ($/ton) *
Reference Case	MISO's MTEP-15 Business As Usual future assumptions**	-
Building Block 1	In 2020, apply a 6% heat rate improvement to all the coal-fired units at a capital cost of $100/kW (amortized over 10 years).	5
Building Block 2	Calculate and enforce, starting in 2020, a minimum fuel burn for existing CC units to yield an annual 70% capacity factor.	53
Building Block 3	Calculate and add the equivalent amount of wind MWs to meet the incremental regional non-hydro renewable target.	237 Present value calculation for costs is the driver for the higher cost.
Building Block 4	Calculate the amount of energy savings for the MISO footprint and incorporate it as a 20-year EE program in the model.	70
All Building Blocks	Application of all building blocks.	60
CO_2 Constraint	Application of a mass-based CO_2 reduction target, allowing the model to optimize.	38

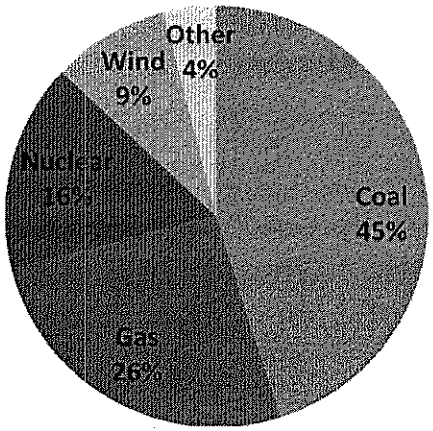
*** The cost per ton of CO_2 reduction is indicative – actual values may vary depending on different input assumptions, etc.**

**** Assumptions matrix is available at https://www.misoenergy.org/Events/Pages/PAC20140820.aspx**

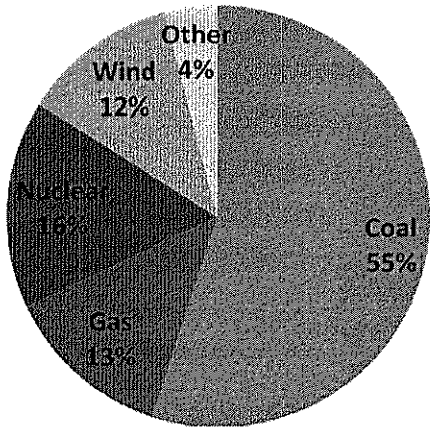
2030 MISO system energy generation forecast under Phase 1 scenarios



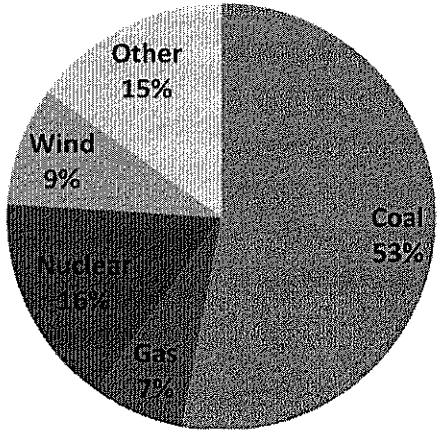
1: Heat Rate Improvement



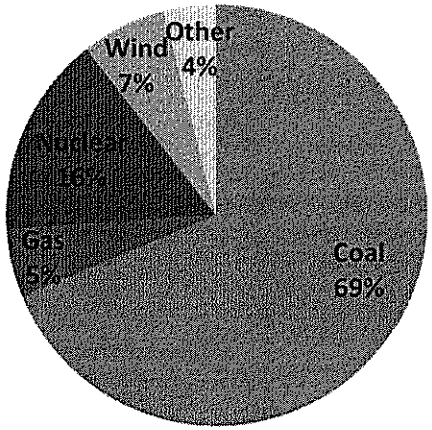
2: Re-dispatch CC up to 70%



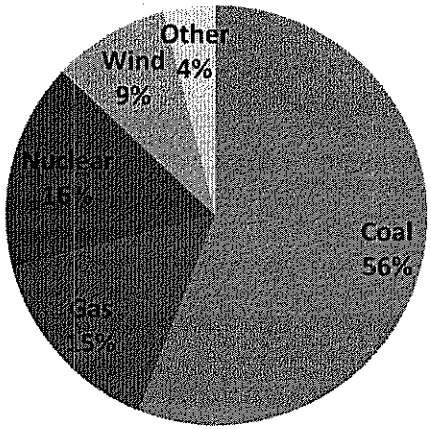
3: Renewable Energy



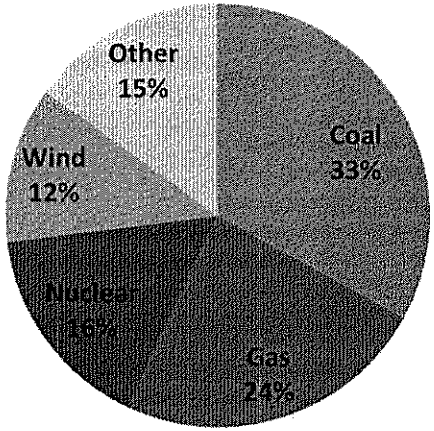
4: Energy Efficiency



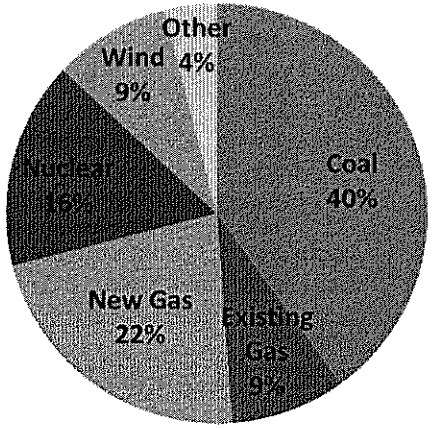
2014: Where are we today?



Reference Case



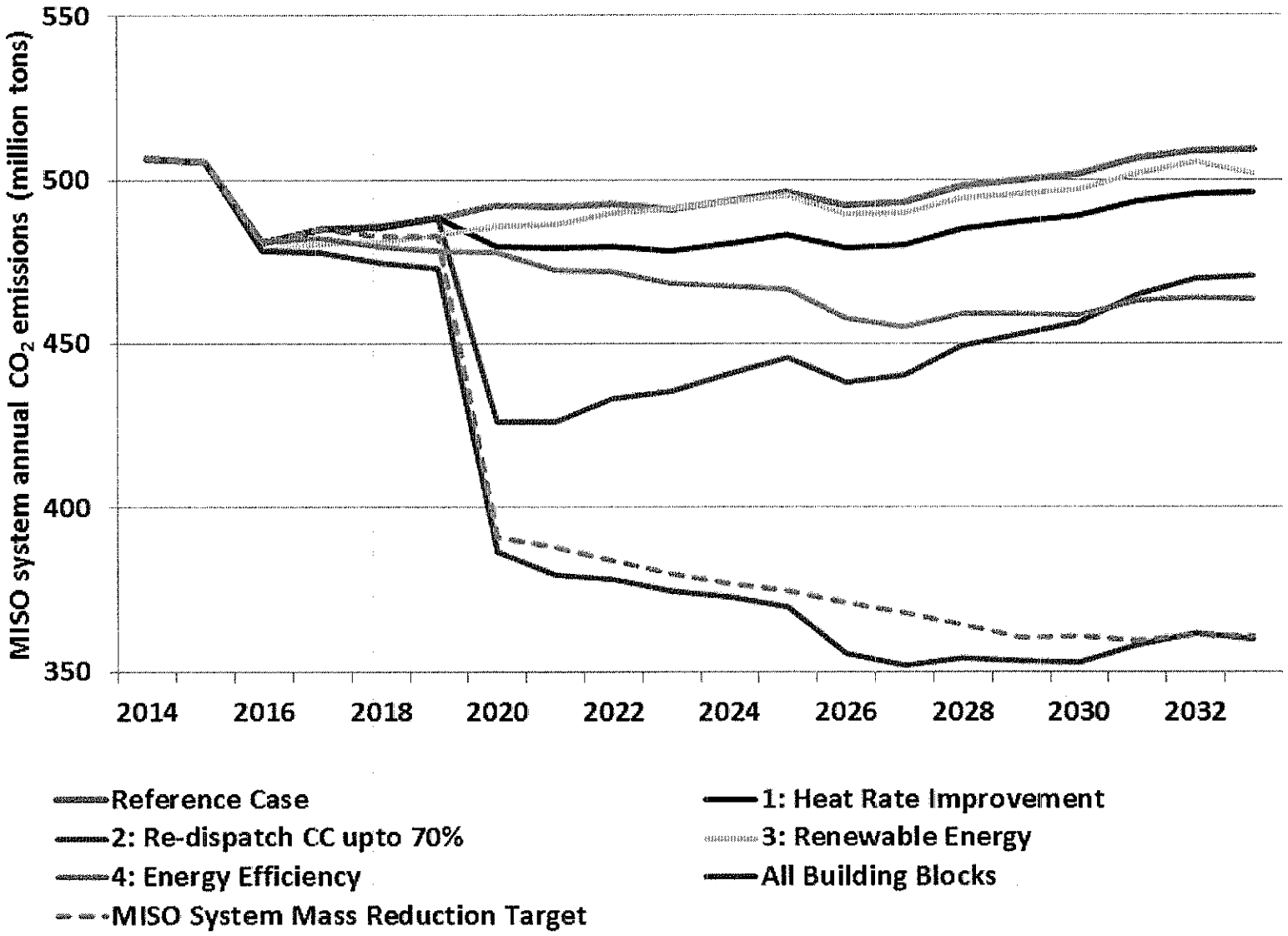
All Building Blocks



CO_2 Constraint

In all the scenarios except the CO_2 constraint, energy production from new gas is less than 2.3%
"Other" category includes energy from biomass, hydro, demand response, energy efficiency and solar.
The results shown for the CO_2 Constraint case are indicative. Further model optimization is required as shown in Phase 2 which indicates potential additional value from increased energy efficiency and coal retirements.

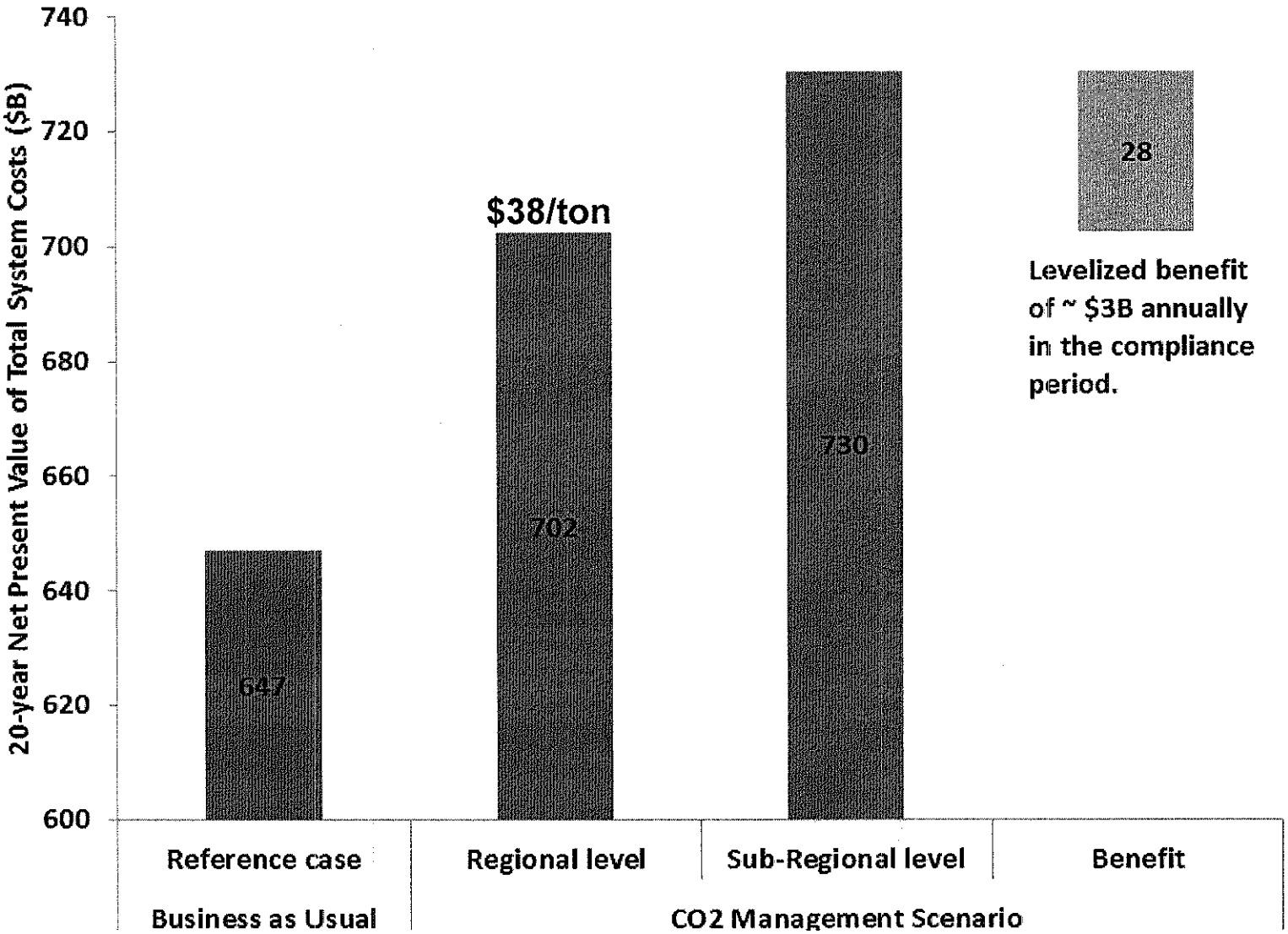
MISO system CO_2 emissions forecast under Phase 1 scenarios



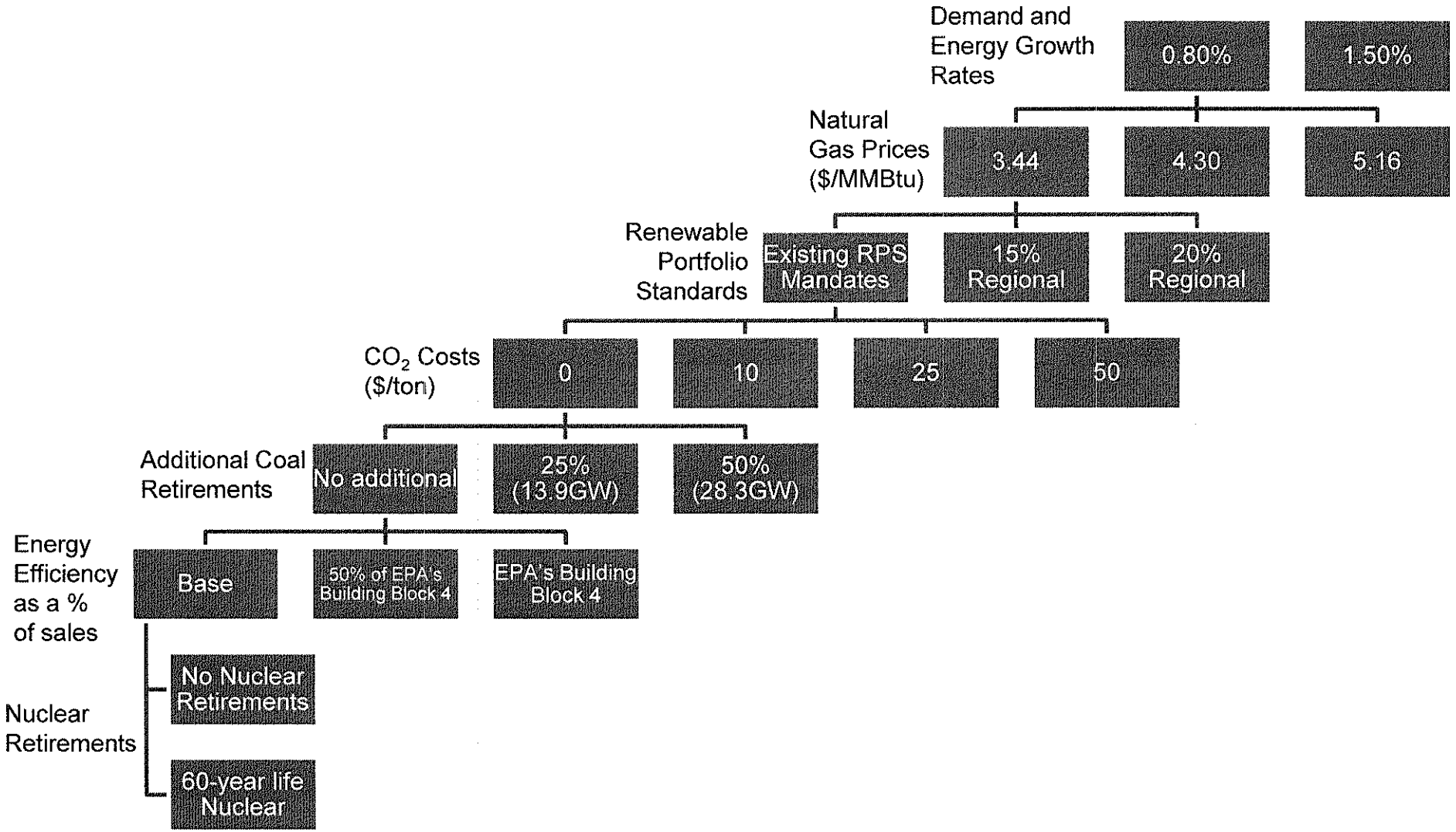
Thinking outside the blocks

- The model can select a least-cost solution that meets a user-defined CO_2 target by considering various alternatives.
  - For example, adding new Combined Cycle generation to meet demand and energy needs could be a least-cost solution as its emissions are not included in the proposed EPA's emissions rate calculation
- Using the model's functionality:
  - Set equivalent mass reduction targets as a CO_2 constraint for regional and sub-regional cases
  - Compare the total cost of the regional vs. sub-regional cases
  - Compliance cost is defined as the difference in the net present value of total system costs between the scenario and the reference cases

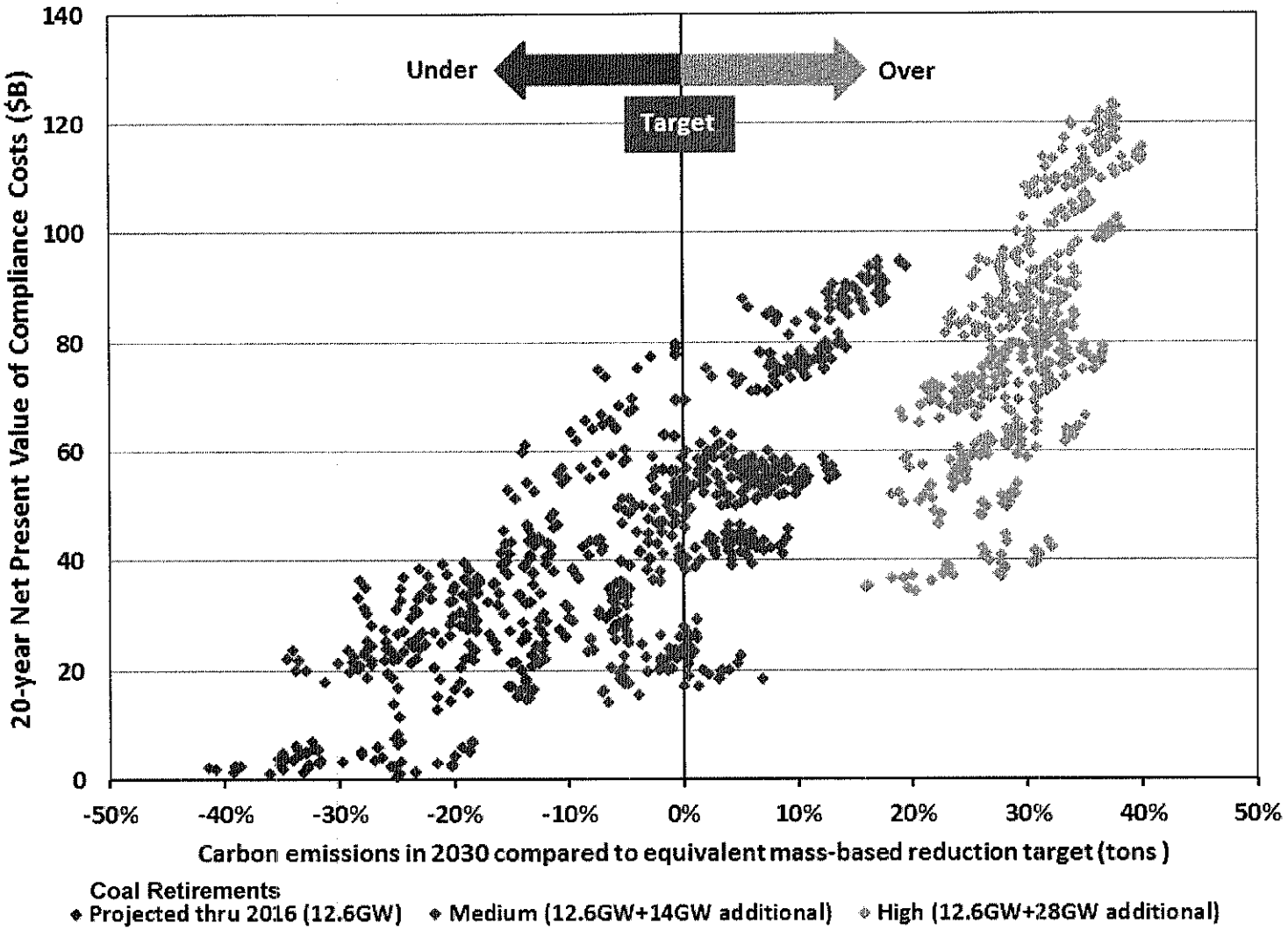
Regional compliance options save approximately $3B annually compared to sub-regional compliance



Phase 2: All possible combinations of the following policy and economic sensitivities were modeled



Lower cost compliance strategies to implement the proposed CO_2 rule put an additional 14GW of coal capacity at-risk for retirement



Study findings

- The Phase 1 results indicate that:
  - Alternative compliance options could achieve the proposed level of CO_2 reduction at a lower cost relative to the application of all the EPA building blocks
  - Regional compliance options save approximately $3B annually compared to sub-regional compliance
- The Phase 2 results indicate that up to an additional 14GW of coal capacity could be at-risk for retirement

Next Steps…

- MISO can provide additional details behind the modeling, including sub-regional data, based on stakeholder interest
- MISO will develop the scope of work for the next round of analyses based on stakeholder feedback
  - Thank you for the feedback already submitted
  - Please provide any additional feedback to Aditya Jayam Prabhakar (ajayamprabhakar@misoenergy.org)

Additional questions? Please contact:

- Aditya Jayam Prabhakar
  - ajayamprabhakar@misoenergy.org

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Appendix

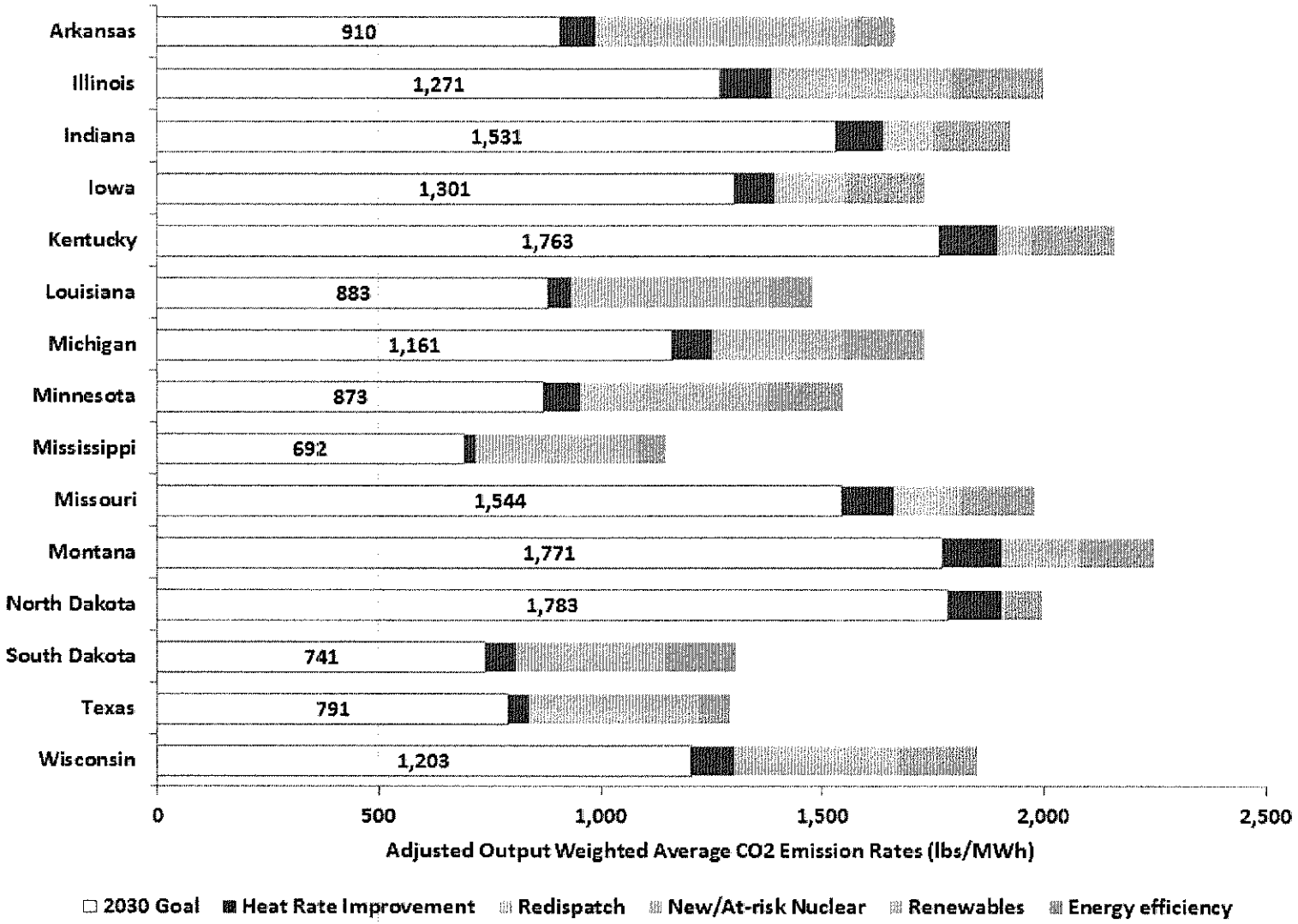
Promulgated under the authority of Section 111(d) of the Clean Air Act, the EPA's CO_2 emissions rule for existing power plants:

- Proposes state-specific emission rate-based CO_2 goals with various options for flexibility in compliance.
- Offers guidelines for the development, submission and implementation of state plans to address greenhouse gas (GHG) emissions from existing fossil-fired electric generating units (EGUs).
- Reflects the emissions reductions that can be achieved by the application of the *Best System of Emission Reduction (BSER) … adequately demonstrated*.

The EPA's definition of BSER is based on four "building blocks" of emissions reduction

Building Blocks			
1. Improve efficiency of existing coal plants	2. Increase reliance upon CC gas units	3. Expand use of renewable resources and sustain nuclear power production	4. Expand use of demand-side energy efficiency
EPA Calculations/Assumptions in the Proposed State Goal Development			
6% efficiency (heat rate) improvement across the fleet, assuming best practices and equipment upgrades	Re-dispatch of CC gas units up to a capacity factor of 70%	Meet regional non-hydro renewable target, prevent the retirement of at-risk nuclear capacity and promote the completion of nuclear capacity under construction	Scale to achieve 1.5% of prior year's annual savings rate

Application of the EPA's Building Blocks to each MISO state's power generation resource mix



The regulation allows flexibility in developing state compliance plans, and offers possible compliance options:

- Co-firing or switching to natural gas
- Carbon capture and sequestration
- New natural gas combined cycle generation capacity
- Heat rate improvements for oil, gas-fired, CC and combustion turbine (CT) units
- Co-firing lower carbon fuels
- Transmission efficiency improvements
- Energy storage technology
- Retirements
- Market-based trading programs