IN THE UNITED STATES DISTRICT COURT
FOR THE WESTERN DISTRICT OF PENNSYLVANIA

Commonwealth of Pennsylvania, Department of Environmental Protection, State of Connecticut, State of Maryland, State of New Jersey, and State of New York, Plaintiffs, v. Allegheny Energy, Inc., Allegheny Energy Service Corp., Allegheny Energy Supply Co., LLC, Monongahela Power Co., The Potomac Edison Co., and West Penn Power Co., Defendants.	Civil Action No. 05-885

FINDINGS OF FACT AND CONCLUSIONS OF LAW

CONTI, Chief District Judge

This matter is before the court following a bench trial. Plaintiffs Commonwealth of Pennsylvania, Department of Environmental Protection ("Pennsylvania DEP"), and the States of Connecticut, Maryland, New Jersey, and New York (together with Pennsylvania DEP, collectively "plaintiffs") seek relief under (1) Part C of Title I of the Clean Air Act ("CAA"), 42 U.S.C. §§ 7404–7479; (2) the new source performance standards ("NSPS") of the CAA, 42 U.S.C. § 7411; and (3) Title V of the CAA, 42 U.S.C. §§ 7661–7661f. Plaintiffs allege that defendants Allegheny Energy, Inc., Allegheny Energy Service Corporation, Allegheny Energy Supply Company, LLC, Monongahela Power Company, the Potomac Edison Company and West Penn Power Company (collectively "Allegheny" or "defendants") violated the CAA by (1) modifying and operating major emitting facilities without obtaining permits and without abiding by emissions limitations required under the prevention of significant deterioration ("PSD") provisions of the CAA; (2) reconstructing and operating two units at a major emitting facility without limiting emissions as required by the NSPS of the CAA; and (3) operating a major emitting facility without obtaining permits as required by Title V of the CAA.

Plaintiff Pennsylvania DEP also brings claims pursuant to the Pennsylvania Air Pollution Control Act ("APCA"), 35 PA. STAT. §§ 4001–4015. Pennsylvania DEP alleges that Allegheny: (1) failed to abide by the emissions limitations required by the PSD provisions under Pennsylvania law, 25 PA. CODE §§ 127.81–.83; (2) failed to abide by the emissions limitations in Pennsylvania nonattainment new source review provisions ("nonattainment NSR"), 25 PA. CODE §§ 127.201–.218; (3) failed to abide by the emissions limitations required under the NSPS provision of Pennsylvania law, 25 PA. CODE §§ 122.1–.3; (4) failed to obtain pre-construction approval for its projects, including the use of the best available technology ("BAT") standards for its facilities as required by law, 25 PA. CODE §§ 127.11–.51; and (5) failed to obtain Title V operating permits as required by law, 25 PA. CODE §§ 127.401–.464.

Specifically, the projects at issue are (1) the replacement of the boilers of Units 1 and 2 of the Armstrong Plant located in Washington Township, Armstrong County, Pennsylvania ("Armstrong"); (2) replacement of portions, including but not limited to the secondary superheater outlet headers, the reheater, and the lower slope tube panels, of Units 1, 2, and 3 at the Hatfield's Ferry Plant located in Green County, Pennsylvania ("Hatfield"); and (3) replacement of the lower slope tube panels at Unit 3 of the Mitchell Plant located in Courtney, Washington County, Pennsylvania ("Mitchell"), as they relate to the emission of nitrogen oxides ("NO_X").

Plaintiffs seek a permanent injunction and civil penalties. The court must decide four preliminary issues: (1) whether certain trial exhibits are admissible; (2) whether the closure of the plants at issue renders the injunctive relief claims moot; (3) whether plaintiffs established that the statute of limitations should be equitably tolled; and (4) whether the court has jurisdiction over plaintiffs' Title V claims. The court must decide three substantive questions: (1) whether any of the projects violated the PSD provisions of the CAA (counts 1, 7, 15, 17, 19, and 23); (2) whether the Armstrong projects were reconstructions which triggered the NSPS of the CAA (counts 4 and 10); and (3) whether Allegheny violated parallel provisions of Pennsylvania law (counts 2, 3, 5, 6, 8, 9, 11, 12, 16, 18, 20, and 24).[1]

This court has subject-matter jurisdiction over the claims in this case pursuant to 42 U.S.C. § 7604(a) and 28 U.S.C. § 1331. The relief requested is authorized pursuant to 42 U.S.C. § 7604 and 28 U.S.C. §§ 2201 and 2202. Venue lies in the United States District Court for the Western District of Pennsylvania pursuant to 42 U.S.C. § 7604(c) and 28 U.S.C. § 1391(b) and (c) because the plants at issue are located in this district.

This matter was bifurcated between liability and damages. A bench trial on liability was held before Chief Judge Gary L. Lancaster from September 13 through September 23, 2010. Chief Judge Lancaster passed away on April 24, 2013. This matter was then reassigned to the undersigned judge. The parties agreed to stand on the record at the status conference held July 11, 2013. The credibility of all the witnesses that testified was assessed based upon the review of the record.

The court considered the evidence adduced at trial, the law applicable to this case, and the submissions of the parties, including extensive proposed findings of fact and conclusions of law and supplemental briefing on developments that occurred post trial. Set forth below are the court's findings of fact and conclusions of law pursuant to Rule 52(a) of the Federal Rules of Civil Procedure. Because the court finds (1) the PSD claims at Armstrong are moot with respect to injunctive relief and time barred with respect to damages; (2) this court lacks subject-matter jurisdiction over the Title V claims; (3) the projects at Hatfield and Mitchell were routine

1 Plaintiffs limited the scope of counts 17–26 by stipulating to the withdrawal of claims arising from certain pollutants and projects. (ECF No. 245.)

maintenance, repair, and replacement; and (4) the projects at Armstrong were not reconstructions or otherwise subject to new source regulations; all as described below, the court finds that defendants are not liable to plaintiffs on any claim.

I. Findings of Fact

Set forth below are the court's findings of fact with respect to the parties, the operation of coal-fired power plants, and those facts relevant to the determination whether the projects at issue were "major modifications," which triggered the PSD requirements, or were "routine maintenance, repair and replacement." 40 C.F.R. § 52.21(b)(2)(i), (iii)(*a*). As a result of the findings of fact with respect to whether the projects at issue were "major modifications," the court does not need to reach the emissions issue and, therefore, makes no findings of fact on that issue. Also set forth below are findings of fact regarding whether plaintiffs' Armstrong projects violated the NSPS of the CAA and facts related to whether the statute of limitations should be equitably tolled.

A. The Parties

1. Defendant Allegheny Energy, Inc., is a public utility holding company that owns the five other corporate defendants in this action: Allegheny Energy Service Corporation; Allegheny Energy Supply Company, Monongahela Power Company, The Potomac Edison Company, and West Penn Power Company. (Joint Stipulations—Liability Phase ¶ 1, ECF No. 430 [hereinafter "JS"].)

2. In September 1997, Allegheny Power System, Inc., changed its name to Allegheny Energy. (Pls.' Proposed Findings of Fact ¶ 2, ECF No. 462 [hereinafter "PPF"]; Defs.' Proposed Findings of Fact App. 1, ¶ 1, ECF No. 470 [hereinafter "DPF"].)

3. At the times in issue, Allegheny Energy, Inc., owned all or substantially all of Allegheny Energy Service Corporation, Allegheny Energy Supply Company, Monongahela Power Company, The Potomac Edison Company, and West Penn Power Company or their corporate predecessors. (PPF ¶ 3; DPF App. 1, ¶ 3.)

4. Each defendant is a "person" as that term is defined in 42 U.S.C. § 7602(e). (JS ¶ 3.)

5. This litigation concerns three coal-fired electricity generating stations operated by Allegheny: Armstrong, Hatfield, and Mitchell. (JS ¶ 4.)

6. Each of those power stations is, and was at the time of the projects at issue in this case, a "major emitting facility," as that term is defined in 42 U.S.C. § 7479(1); a "major stationary source" as that term is defined in 40 C.F.R. § 52.21(b)(1)(i)(*b*) and 25 Pa. Code § 127.83; a "major NO_X emitting facility" as that term is defined in 25 Pa. Code § 121.1; and a "major facility" for sulfur dioxide ("SO_2"), as that term is defined in 25 Pa. Code § 121.1. (JS ¶ 5.)

7. On or about May 20, 2004, the Attorneys General of New York, Connecticut, and New Jersey and the Chief Counsel of Pennsylvania DEP sent a notice of intent to sue to defendants. (JS ¶ 71.)

8. On or about September 8, 2004, the Attorney General of Maryland sent a notice of intent to sue defendants. (JS ¶ 72.)

9. On or about August 3, 2005, the Attorneys General of New York, Connecticut, Maryland, and New Jersey and the Chief Counsel of Pennsylvania DEP sent a notice of intent to sue to defendants for additional violations under the CAA. Among other things, this notice described the NSPS, BAT, and Title V operating permit claims that plaintiffs assert in this action. (JS ¶ 73.)

10. Each notice was served by certified mail on the U.S. Environmental Protection Agency ("EPA") Administrator, the EPA Regional Administrator for the EPA Region in which the plants are located, the Governor of Pennsylvania, and defendants. (JS ¶ 74.)

11. More than sixty days elapsed between the 2004 notices and the filing of plaintiffs' original complaint in this action, in which plaintiffs' pleaded the claims identified in the 2004 notices. (JS ¶ 75.)

12. More than sixty days elapsed between the 2005 notice and the filing of plaintiffs' first amended complaint in this action, in which plaintiffs' pleaded the additional claims identified in the 2005 notice. (JS ¶ 76.)

B. Coal-Fired Electricity Generating Steam Units

1. Generally

13. A coal-fired power plant burns coal in a boiler to heat water that turns into steam and spins a turbine connected to a generator to produce electricity. (Trial Tr. day 1, 44:1–5, Sept. 13, 2010, ECF No. 436.)

14. As part of this process, the coal is ground to a fine powder in pulverizers. (*Id.* at 46:15–19.)

15. Pulverized coal and air are blown into the inside of the boiler's furnace through burners. The air contains oxygen which is necessary for the coal to burn in the boiler. (*Id.* at 47:13–18, 48:5–10.)

16. The inside of the boiler furnace walls are known as waterwalls because they are composed of tubes with water flowing through them. The lower slopes of a coal-fired boiler are also part of the waterwalls. (PPF ¶ 32; DPF App. 1, ¶ 32.)

17. The burning coal heats the water in the waterwall tubes surrounding the furnace and it turns into steam. (Trial Tr. day 1, 48:14–21, 49:3–15, ECF No. 436.)

18. A header is a large cylinder which collects steam from the numerous tubes in a component, and sends that steam in a single stream to the next component. (*Id.* at 49:8–19.)

19. Water separated in the steam drum returns to the boiler for further heating. (*Id.*)

20. A "supercritical" boiler operates at a pressure greater than 3,200 pounds per square inch. Under this pressure, water and steam are indistinguishable. (*Id.* at 56:16–57:8.)

21. A “subcritical” boiler operates at a pressure below 3,200 pounds per square inch, using a process where steam and water are mixed together, requiring separation in a steam drum. (PPF ¶ 36; DPF App. 1, ¶ 36.)

22. The Armstrong and Mitchell boilers are “subcritical” and the Hatfield boilers are “supercritical.” (Trial Tr. day 1, 56:19–57:2, ECF No. 436.)

23. After leaving the waterwalls or steam drum, the steam travels through other tubes, called superheaters, where it is further heated and achieves the temperature and pressure needed to turn the turbine. (*Id.* at 49:8–25.)

24. When steam leaves the superheater, the steam turns the high pressure turbine. (*Id.* at 49:21–25.)

25. The turbine turns the generator, which converts the mechanical energy of the turbine into electricity. (*Id.* at 56:2–8.)

26. After traveling through the high pressure turbine, the steam returns to the boiler and travels through tubes called reheaters, which increase both the temperature and pressure of the steam. (*Id.* at 56:2–15.)

27. The reheated steam passes through the low-pressure part of the turbine, after which it is condensed into water and returns to the boiler to repeat the process. (*Id.* at 56:2–15.)

28. Before the condensed water flows again into the waterwall tubes, it passes through a component known as the economizer, where it is heated by combustion gases before they pass through pollution controls and the stack. (*Id.* at 50:14–23.)

29. Before entering the stack, hot combustion gases also pass through an air heater and heat the incoming air. (*Id.* at 50:14– 51:10.)

30. Leaving the boiler and passing through pollution controls, if any, combustion gases are discharged into the atmosphere through the stack. (*Id.* at 53:9–54:10.)

31. SO_2 in the exhaust gases can be reduced by scrubbers, which are also called "flue gas desulfurization units." (*Id.* at 54:11–19.)

32. NO_x in the combustion gases can be reduced by selective catalytic reduction units. (*Id.* at 55:12–56:1.)

33. Another method of reducing NO_x emissions is the use of low-NO_x burners, which produce fewer oxides in nitrogen when combusting coal than prior generations of burners. (*Id.* at 47:19–48:4.)

34. Continuous emission monitors measure the amount of pollutants emitted from the stack on a continuous basis. (*Id.* at 55:1–11.)

35. A kilowatt hour is a unit of energy equal to one thousand watts of electricity used for one hour. (Trial Tr. day 4, 17:20–18:9, Sept. 21, 2010, ECF No. 437.)

36. A megawatt hour is a unit of energy equal to one million watts of electricity used for one hour. (*Id.* at 17:20–18:9.)

37. A British Thermal Unit ("BTU") is a unit of energy. Approximately 3,413 BTUs equal one kilowatt hour.

38. The terms "unit rating," "unit capability," and "unit capacity" all refer to the maximum amount of electricity, typically expressed in megawatts, that a unit can generate at full power. (Trial Tr. day 3, 10:17–11:2, Sept. 20, 2010, ECF No. 434.)

39. "Heat rate" is a measure of the efficiency of a generating unit and is the amount of heat energy, typically expressed in BTUs, required to generate one kilowatt hour of electricity. (*Id.* at 10:6–10:13.)

40. A unit is more efficient (that is, uses less coal to generate the same amount of electricity) when its heat rate is lower. (*Id.* at 10:6–10:16.)

41. An electric generating unit is "available" when it is capable of producing electricity if needed. (Trial Tr. day 2, 200:20–201:5, Sept. 14, 2010, ECF No. 433.)

42. A unit is in "reserve shutdown" when it is available to generate electricity, but that electricity is not needed. (Trial Tr. day 5, 198:23–199:6, Sept. 22, 2010, ECF No. 438.)

43. A unit is "unavailable" during a planned shutdown, known as a planned outage. (Trial Tr. day 2, 200:23–25, 203:2–9, ECF No. 433.)

44. Electric generating utility companies schedule planned outages on a regular basis to conduct repairs of equipment. (*Id.* at 203:6–9.)

45. A unit is also unavailable during an unplanned shutdown, known as an unplanned or forced outage. (*Id.* at 203:10–19.)

46. A forced outage occurs when a sudden problem with the unit renders it unable to generate electricity until the problem is fixed. (*Id.* at 203:10–19.)

47. Boiler tube leaks are the most common cause of forced outages. (*Id.* at 203:20–25.)

48. A single boiler tube leak can shut down a unit for four days. (PPF ¶ 67; DPF App. 1, ¶ 67.)

49. A "derating" occurs when a unit can operate, but not at its maximum capacity because of an equipment problem. (Trial Tr. day 2, 201:11–17, ECF No. 433.)

50. An electric generating unit consists of thousands of independently operating components that must be kept functioning in order to produce electricity. (Trial Tr. day 6, 28:23–29:6, 180:11–12, Sept. 23, 2010, ECF No. 439.)

51. These thousands of components have differing wear rates, and the failure of almost any of them can cause a forced outage or derating. (*Id.* at 180:11–14.)

52. Utility companies, including Allegheny, prefer to schedule repair and replacement work during planned outages, rather than wait for worn components to break and cause a forced outage. (Trial Tr. day 7, 214:12–20, Sept. 27, 2010, ECF No. 448.)

53. Forced outages tend to stress the unit and impose higher costs on the utility company and ratepayers. (*Id.* at 211:25-212:23.)

54. A unit's availability factor is the percentage of time in a year that a unit was available to generate electricity if needed because it was not shut down for planned maintenance or forced outages. (PPF ¶ 69; DPF App. 1, ¶ 69.)

55. A unit's equivalent availability factor is a refinement of the availability factor that takes into account the effects of deratings and outages on a unit's availability. (Trial Tr. day 2, 201:11–202:11, ECF No. 433; Trial Tr. day 4, 42:19–22, ECF No. 437.)

56. The utilization factor of a unit is the percentage of time the unit is actually operated when it is available to operate. (Trial Tr. day 4, 42:23–43:1, ECF No. 437.)

57. The capacity factor of a unit measures its rate of use. Capacity factor is the percentage of maximum output that is actually generated in a given time period. (*Id.* at 22:19–23:11.)

58. For example, a unit with a 70 percent capacity factor in a year produced 70 percent of the energy, typically expressed in megawatt hours, that it could have generated had it operated at full power for the entire year. (*Id.* at 22:19–23:8.)

59. A unit is "baseloaded" when it is operated all or most of the time it is available. (Trial Tr. day 2, 202:12–203:1, ECF No. 433.)

60. The manner in which a utility treats a repair or replacement project for accounting purposes—i.e., when determining whether to classify a project as "maintenance" or "capital" expenditure—is governed by a set of industry-wide

accounting rules and guidelines, as set forth by the Federal Energy Regulatory Commission ("FERC"). (Trial Tr. day 8, 46:11–18, Sept. 28, 2010, ECF No. 449.)

61. Under FERC's Uniform System of Accounts for electric generating facilities, Allegheny is required to treat certain component replacements as "capital" projects. (*Id.* at 46:11–18.)

62. Typically, Pennsylvania DEP did not require plan approvals for routine boiler tube replacements. (Trial Tr. day 7, 44:18–24, ECF No. 448.)

63. Pennsylvania DEP knew that coal-fired power plant operators were replacing large sections of boiler tubes, but never indicated that component replacements required a PSD permit. (Trial Tr. day 2, 180:20–181:1, ECF No. 433; Trial Tr. day 7, 76:14–15, ECF No. 448.)

64. Pennsylvania DEP did not refuse to issue a single Title V operating permit during the late 1990s and early 2000s on the basis that replacing large sections of boiler tubing or boiler components triggered PSD or nonattainment NSR. (Trial Tr. day 2, 181:15–21, ECF No. 433.)

65. Pennsylvania DEP did not notify Allegheny, prior to 2005, that PSD permits were required for like-kind component replacements. (Trial Tr. day 6, 152:21–153:3, 166:9–18, ECF No. 439.)

66. Only once prior to the start of its nonattainment NSR enforcement initiative in 1999 did the EPA make a formal determination that a power plant component replacement project was a "modification" that triggered federal PSD rules; the project was proposed by Wisconsin Electric Power Company ("WEPCo") to extend the life of its coal-fired Port Washington plant. (*Id.* at 35:19–21.)

67. In September 1988, the EPA issued the "Clay Memorandum," an applicability determination for the WEPCo project. The EPA determined that this project was "unprecedented" and triggered the PSD rules because it was not routine maintenance, repair, or replacement. Memorandum from Don R. Clay, Acting

Assistant Adm'r for Air and Radiation to David A. Kee, Dir., Air and Radiation Div., Region V (Sept. 9, 1988) (Def.'s Ex. 1824), at 3–4 [hereinafter "Clay Memorandum"].

68. Plaintiffs' expert Richard Koppe ("Koppe") was not aware of any electric utility, prior to 2000, seeking a PSD permit for component replacements like those at issue here. (Trial Tr. day 2, 146:14–21, ECF No. 433.)

2. Facts Common to All Projects

69. The projects at issue are (1) the replacement of the boilers at Units 1 and 2 at Armstrong; (2) replacement of secondary superheater outlet headers, the reheater, and lower slope tube panels of Units 1, 2, and 3 at Hatfield; and (3) replacement of the lower slope tube panels of Unit 3 at Mitchell as they relate to the emission of NO_X.

70. Allegheny replaced the components at issue during planned outages when, consistent with Allegheny's usual maintenance practices, other maintenance activities and repairs to equipment not at issue were performed. (Trial Tr. day 6, 48:12–22, ECF No. 439.)

71. For example, low-NO_X burners were installed contemporaneously with the Armstrong and Mitchell projects at issue, as well as during the replacement in 1993 of the Hatfield Unit 2 pendant reheater. (DPF ¶ 26; Pls.' Resp. Ex. A, ¶ 26, ECF No. 480-1.)

72. Allegheny performed the projects at issue to prevent or reduce future problems with some or all of the components at issue. (Trial Tr. day 7, 211:25–213:24, ECF No. 448; Trial Tr. day 3, 28:8–14, ECF No. 434.)

73. The economic evaluations justifying the projects referred to improved future availability and reliability, based upon cost-benefit analyses that compared the future if the projects were not performed versus the future if the projects were performed. (Trial Tr. day 6, 175:5–15, ECF No. 439; DPF ¶ 30; Pls.' Resp. Ex. A, ¶ 30.)

74. Allegheny treated the costs of the projects as “capital” expenditures, in keeping with FERC requirements. (Trial Tr. day 7, 102:11–13, ECF No. 448; DPF ¶ 34; Pls.’ Resp. Ex. A, ¶ 34.)

75. Outside contractors performed each of the projects at issue. (Trial Tr. day 8, 49:12–18, ECF No. 449; DPF ¶ 35; Pls.’ Resp. Ex. A, ¶ 35.)

76. The eight component replacements at issue consisted primarily of replacement of sections of boiler tubes or headers connected to the tube sections. (Trial Tr. day 7, 127:1–4, ECF No. 448; DPF ¶ 19; Pls.’ Resp. Ex. A, ¶ 19.)

77. The new replacement components were of like kind and functionally equivalent to those that were replaced, although they incorporated some design improvements. (Trial Tr. day 7, 124:6–16, 129:2–22, 140:20–141:3, ECF No. 448.)

78. None of the replacements changed the capacity or steaming rates of the units at issue, meaning that the maximum amount of steam and electricity that each unit could generate did not increase after any of the projects. (*Id.* at 129:14–22, ECF No. 448; Trial Tr. day 6, 159:3–11, ECF No. 439.)

79. None of the projects at issue caused any of the units to move within Allegheny’s system “dispatch order” or increased the extent to which the units were called upon to generate electricity. (Trial Tr. day 5, 159:19-160:10, ECF No. 438.)

C. Hatfield

1. Generally

80. Hatfield is located in Greene County, Pennsylvania. (JS ¶ 16.)

81. Hatfield included three units that generated electricity: Units 1, 2, and 3. Each unit burned coal as its primary fuel. (JS ¶ 17.)

82. Unit 1 went into service in 1969. (JS ¶ 18.)

83. Unit 2 went into service in 1970. (JS ¶ 19.)

84. Unit 3 went into service in 1971. (JS ¶ 20.)

85. Hatfield shut down on October 9, 2013. (Second Notice of Subsequent Developments, ECF No. 516.)

86. Each Hatfield unit was an "electric utility steam generating unit" within the meaning of 40 C.F.R. § 60.2 and 25 Pa. Code § 122.3 (as made federal law by 40 C.F.R. §§ 52.2020–.2062). (JS ¶ 21.)

87. Each Hatfield Unit was baseloaded during the period at issue in this case. (Trial Tr. day 2, 202:22–203:1, ECF No. 433.)

88. At all times relevant to this action, Greene County, Pennsylvania, where Hatfield is located, was in attainment or unclassifiable for both SO_2 and NO_X. (JS ¶ 22.)

89. Allegheny installed low-NO_X burners at Hatfield Unit 1 during an outage that ran from October 2, 1994, through November 23, 1994. (JS ¶ 23.)

90. Allegheny installed low-NO_X burners at Hatfield Unit 2 during an outage that ran from September 25, 1993, through December 3, 1993. (JS ¶ 24.)

91. Allegheny installed low-NO_X burners at Hatfield Unit 3 during an outage that ran from February 25, 1995, through May 8, 1995. (JS ¶ 25.)

2. Hatfield Unit 1 Lower Slope Project

92. Allegheny began planning the Hatfield Unit 1 lower slope project in 1995, more than two years before performing it. (JS ¶ 26.)

93. Allegheny performed this project during an outage that took place from October 11, 1997, to December 20, 1997. (JS ¶ 27.)

94. The project involved completely replacing the lower slope tubes, seal skirt, and ash hopper in a manner that allowed for design improvements such as thicker tubes and redesigned materials and configuration of the furnace seals to improve their longevity. (JS ¶ 28.)

95. The slope tube panels in each unit are about sixty feet wide. (PPF ¶ 308; DPF App. 1, ¶ 308.)

96. Each new slope panel included 464 tubes, and the slope panel replacement was just one aspect of the projects. (PPF ¶ 309; DPF App. 1, ¶ 309.)

97. The purpose of the Hatfield lower slope replacement project was to improve the reliability and availability of the boiler. (PPF ¶ 311.)

98. The work was performed by outside contractors using materials fabricated by outside contractors. (JS ¶ 29.)

99. The total cost of the project was $5,918,077. (JS ¶ 31.)

100. Allegheny treated the cost of the project as a capital expenditure, not a maintenance expense, for accounting purposes. (JS ¶ 32.)

3. Hatfield Unit 1 Secondary Superheater Outlet Header Project

101. Allegheny performed this project during an outage that took place from October 11, 1997, to December 20, 1997. (JS ¶ 33.)

102. Allegheny began planning the project more than two years before performing it. (JS ¶ 34.)

103. The project involved replacing both secondary superheater outlet headers at Hatfield Unit 1 with newly fabricated outlet headers that were an upgraded design made with stronger material. (JS ¶ 35.)

104. The work was performed by outside contractors using material fabricated by outside contractors. (JS ¶ 36.)

105. Each secondary superheater outlet header that was replaced was sixty feet long and weighed 90,000 pounds. (PPF ¶ 397; DPF App. 1, ¶ 397.)

106. Each header had approximately 100 tubes connected to it. (Trial Tr. day 3, 34:18–35:18, ECF No. 434.)

107. These tubes had to be cut free from the header, and a rigging had to be constructed for each tube to prevent it from falling. (PPF ¶ 399; DPF App. 1, ¶ 399.)

108. The outside contractors made a hole in the roof of the building and used a huge crane to reach over the top of the building to lift the old headers out and install the new ones. (PPF ¶ 400; DPF App. 1, ¶ 400.)

109. Each 90,000 pound secondary superheater outlet header had to be cut into five pieces to make it easier to lift out. (PPF ¶ 401; DPF App. 1, ¶ 401.)

110. The new secondary superheater outlet headers weighed 40,000 pounds each, and the crane lifted them through the hole in the roof in two parts. (PPF ¶ 402; DPF App. 1, ¶ 402.)

111. After the new secondary superheater outlet headers were lifted into the boiler, they were rigged in place and the hundreds of tubes were welded to the tube stubs on the new header. (PPF ¶ 403; DPF App. 1, ¶ 403.)

112. The total cost of the project was $2,513,016. (JS ¶ 37.)

113. Allegheny treated the cost of the project as a capital expenditure, not a maintenance expense, for accounting purposes. (JS ¶ 38.)

114. Prior to this project, Allegheny had not previously replaced the Hatfield Unit 1 secondary superheater outlet headers. (JS ¶ 39.)

4. Hatfield Unit 2 Reheater Project

115. Allegheny began planning this project at least eighteen months before it was performed. (JS ¶ 40.)

116. Allegheny performed the project during a planned outage from September 25, 1993, to December 3, 1993. (JS ¶ 41.)

117. The work was performed by outside contractors, not Allegheny's own maintenance employees. (JS ¶ 46.)

118. The project involved removing the existing reheater assemblies and crossover tubes and replacing them with newly fabricated assemblies made of a different material that Allegheny anticipated would be more resistant to corrosion. (JS ¶ 42.)

119. The pendant reheater consisted of 125 pendants (assemblies of tubing) suspended from a header near the top of the boiler. (PPF ¶ 369; DPF App. 1, ¶ 369.)

120. Each of the 125 pendants weighed several thousand pounds, contained 700 feet tubing and was approximately 40 feet high and 20 feet long. (PPF ¶ 370; DPF App. 1, ¶ 370.)

121. The total tubing in the pendant reheater was approximately seventeen miles long. (PPF ¶ 371; DPF App. 1, ¶ 371.)

122. Contractors performed 2,265 individual welds to attach the tubing of the new pendant reheater. (PPF ¶ 372; DPF App. 1, ¶ 372.)

123. Allegheny expected the project to reduce forced outages caused by the reheater. (JS ¶ 43.)

124. The total cost of the project was $5,692,777. (JS ¶ 44.)

125. Allegheny treated the cost of the project as a capital expenditure, not a maintenance expense, for accounting purposes. (JS ¶ 45.)

126. Although Allegheny had previously replaced some of the crossover tubes, it had never previously replaced the entire pendent reheater or all the crossover tubes. (JS ¶ 47.)

5. Hatfield Unit 2 Lower Slope Project

127. Allegheny began planning for the Hatfield Unit 2 lower slope project in early 1995. (JS ¶ 48.)

128. Allegheny performed this project during a twelve-week outage from September 3, 1999, to November 26, 1999. (JS ¶ 49.)

129. The project involved removing lower slope panels, inlet headers, seal skirt, and ash hopper and replacing those items in their entirety with newly fabricated materials that Allegheny variously described as involving "an improved design," an "upgraded design," and a "redesign of the lower furnace area in order to take advantage of improvements such as: thicker tubing to address slope erosion and corrosion problems, an improved structural support system to better resist damage from slag falls, improved materials and configuration of the furnace seals to provide a longer service life, and upgraded ash hoppers to improve ash handling capabilities." (JS ¶ 50.)

130. Allegheny hired outside contractors to fabricate the new materials and to do the demolition, removal, and installation work required by the project. (JS ¶ 51.)

131. In a June 1995 memorandum, Allegheny employee William Maiden recommended the project be undertaken "[t]o increase the availability and reduce future maintenance and operating costs of Hatfield's Ferry Power Station . . . ." (JS ¶ 52.)

132. Allegheny had never before replaced the entire lower slopes at Hatfield Unit 2. (PPF ¶ 335; DPF App. 1, ¶ 335.)

133. In a May 1998 "project economic evaluation system" memorandum, Allegheny explained that "forced outages in the lower slope area will be reduced to a zero baseline" by replacing the Hatfield Unit 2 "lower slope tubes, first and second pass inlet headers, seal skirt and ash hoppers." (JS ¶ 53.)

134. The total cost of the project was $6,342,917. (JS ¶ 54.)

135. Allegheny treated the cost of the project as a capital expenditure, not as a maintenance expense, for accounting purposes. (JS ¶ 55.)

6. *Hatfield Unit 3 Lower Slope Project*

136. Allegheny began planning to replace the Hatfield Unit 3 lower slope tube panels over one year before performing it. (JS ¶ 56.)

137. Allegheny performed this project during an outage that ran from September 20, 1996, through December 1, 1996. (JS ¶ 57.)

138. The project involved the wholesale replacement of the lower slope tube panels, and the replacement of the seal skirt with an improved design. (JS ¶ 58.)

139. The work was performed by an outside contractor using materials fabricated by a different outside contractor. (JS ¶ 59.)

140. The replacement of the lower slopes required disconnecting the headers from the pipes that bring water into them, disconnecting all the old tubes in the lower slopes from the remainder of the waterwalls, moving the new tube panels into place and supporting them until they are connected, and welding the ends of the new tubes to the rest of the waterwalls. (PPF ¶ 346; DPF App. 1, ¶ 346.)

141. Installing the new lower slopes required over 2,000 welds. (PPF ¶ 347; DPF App. 1, ¶ 347.)

142. The work was done in two ten-hour shifts daily, with approximately fifty-two people working on each shift, six days per week for eight weeks. (PPF ¶ 348; DPF App. 1, ¶ 348.)

143. Allegheny never before replaced the entire lower slopes at Hatfield Unit 3. (PPF ¶ 349; DPF App. 1, ¶ 349.)

144. Allegheny treated the cost of the project as a capital expenditure, not a maintenance expense, for accounting purposes. (JS ¶ 60.)

D. Mitchell

145. Mitchell is located in Washington County, Pennsylvania. (JS ¶ 61.)

146. It had three units. Units 1 and 2 were oil fired. Unit 3 was coal fired. (JS ¶ 62.)

147. Unit 3 went into service in 1963. (JS ¶ 63.)

148. Mitchell shut down on October 9, 2013. (ECF No. 516.)

149. Unit 3 had a net capacity of 288 megawatts. (PPF ¶ 162; DPF App. 1, ¶ 162.)

150. Unit 3 was baseloaded during the 1990s. (PPF ¶ 164; DPF App. 1, ¶ 164.)

151. Unit 3 is an "electric utility steam generating unit" within the meaning of 40 C.F.R. § 60.2 and 25 PA. CODE § 122.3 (as made federal law by 40 C.F.R. §§ 52.2020–.2062). (JS ¶ 64.)

152. Mitchell is located in an area that has been classified as attainment for NO_2 from 1978 to the present. (JS ¶ 65.)

153. Allegheny installed low-NO_X burners at Mitchell Unit 3 during an outage that ran from October 7, 1994, through December 20, 1994. (JS ¶ 66.)

154. In the five-and-one-half years before the Mitchell lower slope project was approved in 1994, the unit experienced an average of 3.8 tube leaks per year. (PPF ¶ 412; DPF App. 1, ¶ 412.)

155. There was an average of seventy-one forced-outage hours per year over the five years before the project was commenced. (PPF ¶ 413; DPF App. 1, ¶ 413.)

156. The Mitchell lower slope project took place during an outage that ran from October 7, 1994, through December 20, 1994. (JS ¶ 67.)

157. The project consisted of replacing twenty-four front and rear ash hopper panels at Mitchell Unit 3. (JS ¶ 68.)

158. The total cost of the project was $626,402. (JS ¶ 69.)

159. The work was performed by outside contractors. (JS ¶ 70.)

160. Allegheny treated the cost of the project as a capital expenditure, not a maintenance expense, for accounting purposes. (PPF ¶ 422; DPF App. 1, ¶ 422.)

E. Routine Maintenance, Repair, and Replacement: Hatfield and Mitchell

1. Generally

161. At trial, Allegheny offered the testimony of an expert, Jerry Golden ("Golden"), regarding what kinds of repair and replacement projects were routine in the industry. (Trial Tr. day 8, 27:10–13, 30:9–16, 33:10–16, 43:9–19, 79:22–80:6, ECF No. 449.) Allegheny also offered the testimony of two of its engineers, William Maiden and Clark Colby.

162. Golden was admitted as an expert in the design, maintenance, and operation of coal-fired power plants; routine maintenance, repair, and replacement ("RMRR"); and estimating the cost of new construction for coal-fired generating units. (Trial Tr. day 7, 208:5–11, ECF No. 448.)

163. At trial, plaintiffs relied almost exclusively on the testimony of their expert Koppe regarding what kinds of repair and replacement projects were routine in the industry. (Trial Tr. day 2, 216:7–218:8, ECF No. 433.)

164. Golden worked at the Tennessee Valley Authority ("TVA") for almost forty years before retiring in 2004 from his position as TVA's General Manager of Environmental Compliance. (Trial Tr. day 7, 175:7–8, ECF No. 448.)

165. Golden compiled data from several different sources on maintenance, repair, and replacement projects performed at coal-fired power stations within the electric utility industry in order to conduct his RMRR analysis. (*Id.* at 197:17–201:1, 205:23–207:12.)

166. For example, Golden collected data regarding documented component replacement activities for which either notices of violation or citations had been issued by the EPA or another agency. (*Id.* at 206:5–207:12; Trial Tr. day 8, 59:12–60:13, ECF No. 449.)

167. Golden also solicited and obtained voluntary information from several different utility companies—including Duke Energy, American Electric Power, First Energy, Southern Company, and TVA—regarding repair and replacement projects performed at their coal-fired power plants. (Trial Tr. day 7, 198:24–201:1, ECF No. 448; Trial Tr. day 8, 61:9–64:9, ECF No. 449.)

168. Golden analyzed information from more than sixty utility companies—representing over 550 of the coal-fired generating units in the United States and more than half the nation's coal-powered generating capacity. (Trial Tr. day 7, 207:1–12, ECF No. 448; Trial Tr. day 8, 66:18–24, ECF No. 449.)

169. From the data he collected, Golden developed a spreadsheet to identify capital projects costing in excess of $100,000 at coal-fired power plants. (Trial Tr. day 8, 47:1–14, ECF No. 449.)

170. Golden identified more than 2,200 pressure part replacement projects that cost more than $100,000 at coal-fired power stations in the United States. (*Id.* at 66:24–25.)

171. Golden examined documents listing pressure part replacements supplied over many years by three original equipment manufacturers ("OEMs")—Alstom, Babcock & Wilcox, and Foster Wheeler. (*Id.* at 71:1–4.)

172. The OEM data show that those three manufacturers provided to the owners or operators of coal-fired electric generating stations 278 reheaters, 674 waterwalls, 81 sections of lower slope and hopper floor tubing, 158 headers, and 51 superheater outlet headers during the relevant time period. (*Id.* at 72:19-23.)

173. In analyzing whether the Hatfield and Mitchell projects at issue were RMRR, Golden analyzed the "WEPCo factors"—nature, extent, purpose, frequency, and cost—on a case by case basis, comparing the project to the industry norms and benchmarks. (*Id.* at 35:1–21.)

174. Based upon his analysis of utility and OEM data, Golden concluded that the nature, extent, purpose, frequency, and cost of the Hatfield and Mitchell projects were consistent with routine industry practices. (*Id.* at 43:17–19, 50:20–22, 73:4–7, 80:3–6, 81:24–82:14.)

a. Nature and Extent

175. Specifically, with respect to the Hatfield and Mitchell projects at issue, the nature of each project was typical of industry-wide boiler component replacement projects. (*Id.* at 43:24–52:14.)

176. In the 1990s, utility companies across the electric generating industry were performing the same kinds of component replacements as were performed at Hatfield and Mitchell. (Trial Tr. day 6, 154:6–14, ECF No. 439; Trial Tr. day 7, 119:18–121:7, ECF No. 448.)

177. The replacement of waterwall tubes was performed regularly by operators in the electric utility industry and was performed regularly at the Allegheny plants at issue in this case. (Trial Tr. day 8, 146:14–147:3, ECF No. 449.)

178. Allegheny engineers actively participated in industry trade groups. (Trial Tr. day 6, 153:19–154:23, ECF No. 439.)

179. Allegheny engineers knew that boiler tube and header replacements, such as those performed in the Hatfield and Mitchell projects at issue, were undertaken frequently in the industry during the 1990s. (Trial Tr. day 7, 119:18–120:17, ECF No. 448.)

180. It is typical in the industry for utility companies to replace worn components with ones of upgraded material or design. (Trial Tr. day 8, 45:8–46:8, ECF No. 449.)

181. The Hatfield and Mitchell projects were performed during planned outages, which is typical for boiler replacements in the industry. (Trial Tr. day 7, 214:8–11, ECF No. 448; Trial Tr. day 8, 47:18–48:1, ECF No. 449.)

182. In particular, boiler pressure part replacements are performed during outages. (Trial Tr. day 8, 47:18–22, ECF No. 449.)

183. Based upon FERC accounting requirements, it is typical throughout the utility industry to capitalize boiler component replacements. (Trial Tr. day 2, 26:11–15, 36:25–37:2, ECF No. 433; Trial Tr. day 7, 100:5–18, 102:2–6, ECF No. 448; Trial Tr. day 8, 46:11–18, ECF No. 449.)

184. It is typical in the utility industry to hire outside contractors to perform replacements of boiler components, including the kinds of components replaced in the Hatfield and Mitchell projects. (Trial Tr. day 8, 48:2–49:18, ECF No. 449.)

185. Golden testified at trial that this kind of work was "always" performed by outside contractors: "I have investigated many, many, many hundreds of projects in the last few years and I can tell you, I have not yet found a single project where the work, single capital project like this where the work was performed by the normal plant maintenance staff." (*Id.* at 48:5–10.)

186. The manner in which Allegheny performed the Hatfield and Mitchell projects was consistent with typical industry component replacement practices. (*Id.* at 52:15–57:12.)

187. The duration of each outage during which the Hatfield and Mitchell projects were performed falls within the normal range of outage lengths at Allegheny and in the coal-fired power industry. (*Id.* at 54:5–15, 56:8–23.)

188. It is typical in the industry for each individual component replacement project to have its own work order and individual justification, and this was done with the Hatfield and Mitchell projects at issue. (*Id.* at 53:4–11.)

b. Purpose

189. Golden analyzed the purposes of the Hatfield and Mitchell projects—which he derived from examining Allegheny's work orders or economic justification

memoranda—and compared them with the purposes of typical replacement projects in the industry. (*Id.* at 38:21–24.)

190. The primary purpose of each of the Hatfield and Mitchell projects was to improve the reliability and availability of the generating units. (*Id.* at 41:19–23.)

191. An additional purpose of the Hatfield Unit 1 secondary superheater outlet header project was to ensure employee safety. (*Id.* at 41:22–23.)

192. These purposes were similar to the purposes of the typical kind of boiler component replacement in the industry. (*Id.* at 39:6–22, 43:9–19.)

c. Frequency

193. Golden identified thousands of pressure part replacement projects that cost more than $100,000 at coal-fired power stations in the United States based upon the business records of utility companies and OEM suppliers, and concluded that the Hatfield and Mitchell projects were typical of the kind performed frequently in the industry. (*Id.* at 57:13–73:7.)

194. It is common for the lower slope sections of coal-fired boilers to suffer erosion and weakening from coal dust, fly ash, and coal slag. (Trial Tr. day 7, 137:8–20, ECF No. 448; Trial Tr. day 8, 44:19–25, 51:23–52:2, ECF No. 449.)

195. Utility companies in the electric generating industry routinely replace, in whole or in part, high-wear areas in their coal-fired boilers, such as lower slope tube panels. (Trial Tr. day 8, 44:19–25, 51:23–52:2, ECF No. 449.)

d. Cost

196. The costs of the Hatfield and Mitchell projects were consistent with RMRR activities in the industry. (*Id.* at 73:17–79:24.)

197. The Hatfield and Mitchell projects at issue ranged from $626,402 for the 1994 Mitchell Unit 3 lower slope project to $6,387,013 for the 1996 Hatfield Unit 3 lower slope project. (JS ¶ 69; DPF ¶ 400; Pls.' Resp. Ex. A, ¶ 400.)

198. The Hatfield and Mitchell projects cost $2.50 to $12 per kilowatt, well below the normal low-end cost of $100 per kilowatt for utility life extension projects. (Trial Tr. day 8, 74:14–25, 78:17–79:24, ECF No. 449.)

199. The WEPCo Port Washington project, which the EPA found was "unprecedented" and not RMRR, cost $70,500,000, or $204 per kilowatt. (*Id.* at 76:11–12, 81:21–23.)

200. The 1986 Beckjord Unit 3 life extension project cost $13,000,000, or $183 per kilowatt. (*Id.* at 76:11–12, 79:5–7.)

e. Plaintiffs' Expert

201. At trial, plaintiffs relied on the testimony of their expert, Koppe, regarding what kinds of repair and replacement projects were routine in the industry. (Trial Tr. day 2, 216:7–218:8, ECF No. 433.)

202. Koppe was qualified as an expert in the areas of utility maintenance practices, power plant performance, reliability of power plant equipment, and the effect of major component replacements on the availability of generating units. (*Id.* at 200:5-13.)

203. Koppe based his opinion upon his electric utility consulting expertise. He projected future availability for power plants for at least thirty utility companies. He testified as an expert on these matters before regulatory agencies more than thirty times. (*Id.* at 195:13–197:22.)

204. Koppe never worked for a boiler OEM. Koppe never worked as a boiler maintenance engineer or superintendent. (Trial Tr. day 3, 124:3–12, ECF No. 434.)

205. Koppe was never involved in the supervision of boiler maintenance outages and was never responsible for preparing maintenance budgets or specifications to be used by contractors and suppliers. (*Id.* at 124:10–21.)

206. Koppe is not an expert on accounting in the utility industry, generation planning, or the dispatch of units within an electric generating system. (*Id.* at 124:22-125:7.)

207. Koppe was not aware of how the EPA viewed the kinds of component replacement projects at issue when it was clarifying its position on the PSD and NSR requirements in the early 1990s. (*Id.* at 137:17–138:5.)

2. *Hatfield Unit 1 Secondary Superheater Outlet Header*

208. The Hatfield Unit 1 secondary superheater outlet header project was typical of component replacements performed during outages at Allegheny generating facilities, although it was the first replacement at Hatfield Unit 1. (Trial Tr. day 6, 58:1–3, ECF No. 439; JS ¶ 39.)

209. Allegheny replaced identical or nearly identical secondary superheater outlet headers at Hatfield Units 2 and 3 and at Allegheny's Fort Martin station in the 1990s. (Trial Tr. day 7, 132:20–133:18, 133:23–134:12, ECF No. 448.)

210. The collective size of the replaced Hatfield Unit 1 secondary superheater outlet headers was small compared to the overall size of the boiler section where they were located. (Trial Tr. day 6, 59:17–60:12, 159:16-160:7, ECF No. 439.)

211. The cost of the Hatfield Unit 1 secondary superheater outlet header project was not significant in comparison to both the unit and fleet annual maintenance budgets. (*Id.* at 57:19–23, 60:13-63:4.)

212. The total cost of this project ($2,513,016) divided by the net generating capacity of the unit (555 megawatts or 555,000 kilowatts) equates to a project cost of $4.52 per kilowatt. (JS ¶ 37; DPF ¶ 412; Pls.' Resp. Ex. A, ¶ 412.)

213. By comparison, life extension projects typically cost between $100 and $250 per kilowatt in the 1990s. (Trial Tr. day 6, 59:8–12, ECF No. 439.)

3. *Hatfield Unit 1 Lower Slope*

214. The cost of the Hatfield Unit 1 lower slope project was not significant in comparison to both the unit and fleet annual maintenance costs. (*Id.* at 57:19–23, 60:13–63:4.)

215. The cost of the Hatfield Unit 1 lower slope project ($5,918,077) divided by the net generating capacity in the unit (555 megawatts, or 555,000 kilowatts) equates to a project cost of $10.66 per kilowatt. (JS ¶ 31; DPF ¶ 425; Pls.' Resp. Ex. A, ¶ 425.)

216. The cost per kilowatt was below the typical cost of $100 to $250 per kilowatt for life extension projects in the 1990s. (Trial Tr. day 6, 59:8–12, ECF No. 439.)

4. *Hatfield Unit 2 Lower Slope*

217. The cost of the lower slope project at Hatfield Unit 2 was not significant in comparison to both the unit and fleet annual maintenance budget. (*Id.* at 57:19–23, 60:13–63:4.)

218. The cost of the Hatfield Unit 2 lower slope project ($6,342,917) divided by the net generating capacity of the unit (555 megawatts or 555,000 kilowatts) equates to a project cost of $11.43 per kilowatt. (JS ¶ 54; DPF ¶ 429; Pls.' Resp. Ex. A, ¶ 429.)

219. The cost per kilowatt was below the typical cost of $100 to $250 per kilowatt for life extension projects in the 1990s. (Trial Tr. day 6, 59:8–12, ECF No. 439.)

5. *Hatfield Unit 2 Reheater*

220. The reheater replacement project at Hatfield Unit 2 was typical of component replacements performed during outages at Allegheny, although the entire reheater at Hatfield Unit 2 had not been previously replaced. (*Id.* at 58:1–3; JS ¶ 47.)

221. The total cost of the reheater replacement project ($5,692,777) divided by the net generating capacity of the unit (555 megawatts, or 555,000 kilowatts)

equates to a project cost of \$10.26 per kilowatt. (JS ¶ 44; DPF ¶ 445; Pls.' Resp. Ex. A, ¶ 445.)

222. The cost of the reheater replacement project was below the typical cost of \$100 to \$250 per kilowatt for life extension projects in the 1990s. (Trial Tr. day 6, 59:8–12, ECF No. 439.)

6. *Hatfield Unit 3 Lower Slope*

223. The cost of the Hatfield Unit 3 lower slope project was not significant in comparison to both the unit and fleet annual maintenance budgets. (*Id.* at 57:19–23, 60:13–63:4.)

224. The total cost of the Hatfield Unit 3 lower slope project (\$6,387,013) divided by the net generating capacity of the unit (555 megawatts or 555,000 kilowatts) equates to a project cost of \$11.51 per kilowatt. (DPF ¶ 433; Pls.' Resp. Ex. A, ¶ 433.)

225. The cost of the Unit 3 lower slope project was below the typical cost of \$100 to \$250 per kilowatt for life extension projects in the 1990s. (Trial Tr. day 6, 59:8–12, ECF No. 439.)

7. *Mitchell Unit 3 Lower Slope*

226. The lower slope replacement project at Mitchell Unit 3 was typical of component replacements performed during outages at Allegheny generating facilities, although this scale of replacement had not been done previously in Unit 3. (*Id.* at 58:1–3; Trial Tr. day 3, 55:12–15, ECF No. 434.)

227. The total cost of the Mitchell Unit 3 lower slope project (\$626,402) divided by the net generating capacity of the unit (284 megawatts or 284,000 kilowatts) equates to a project cost of \$2.21 per kilowatt. (DPF ¶ 457; Pls.' Resp. Ex. A, ¶ 457.)

228. The cost of the Unit 3 lower slope replacement project was below the typical cost of $100 to $250 per kilowatt for life extension projects in the 1990s. (Trial Tr. day 6, 59:8–12, ECF No. 439.)

F. Armstrong

1. Generally

229. Armstrong is located in Washington Township, Armstrong County, Pennsylvania. (JS ¶ 7.)

230. Armstrong had two units that generated electricity, Unit 1 and Unit 2, both of which burned coal as their primary fuel. (JS ¶ 8.)

231. Each Armstrong Unit was at all times relevant to this litigation an "electricity generating steam unit" within the meaning of 40 C.F.R. § 60.2 and 25 Pa. Code § 122.3 (as made federal law by 40 C.F.R. §§ 52.2020–.2062). (JS ¶ 11.)

232. Armstrong is located in an area that has been classified as nonattainment for SO_2 since 1978. (JS ¶ 12.)

233. Armstrong is located in an area that was classified as moderate nonattainment for ozone under the one-hour standard from 1978 through October 18, 2001. (JS ¶ 13.)

234. Since October 19, 2001, the area in which Armstrong is located has been in attainment for the one-hour ozone standard. (JS ¶ 14.)

235. The Armstrong power station is located in an area that has been classified as attainment for NO_2 since 1978. (JS ¶ 15.)

236. Unit 1 was placed in service in 1958. (JS ¶ 9.)

237. Unit 2 was placed in service in 1959. (JS ¶ 10.)

238. Armstrong was closed on September 1, 2012. (ECF No. 498, Ex. 2, ¶¶ 2–4.)

239. Units 1 and 2 were subcritical boilers. (Trial Tr. day 1, 57:1–2, ECF No. 436.)

240. Units 1 and 2 each had a capacity of 170 to 180 megawatts. (*Id.* at 57:20–23.)

241. Allegheny decided to install low-NO_x burners at all its coal-fired units, including Armstrong, in order to comply with the requirements of the 1990 CAA Amendments. (Trial Tr. day 5, 164:10–16, ECF No. 438.)

242. In order to accommodate the low-NO_x burners, Allegheny determined that the design of the Armstrong boilers needed to be upgraded to increase airtightness, which required the removal and replacement of a variety of boiler components. (Trial Tr. day 6, 199:2–203:21, ECF No. 439.)

243. Despite the work performed as part of the Armstrong projects, the boilers remained essentially the same after the projects, retaining the same generating capacity, the same steaming rate, and the same steam outlet conditions. (*Id.* at 207:17–208:13.)

244. In 1987, Allegheny hired Foster Wheeler Energy Company ("Foster Wheeler") to evaluate the condition of the Unit 1 boiler. (PPF ¶ 170; DPF App. 1, ¶ 170.)

245. In 1988, Foster Wheeler produced a fitness assessment that documented the condition of the Unit 1 boiler. (PPF ¶ 171; DPF App. 1, ¶ 171.)

246. The objectives of Foster Wheeler's boiler fitness assessment were to evaluate the condition of the steam generating components, recommend methods to maintain or improve the levels of availability and reliability, and enable Allegheny to plan for the continued service of Armstrong Unit 1. (PPF ¶ 172; DPF App. 1, ¶ 172.)

247. Foster Wheeler's assessment report found that many boiler components of Unit 1 were in need of repair, redesign, or replacement. (PPF ¶ 173; DPF App. 1, ¶ 173.)

248. Foster Wheeler did not address reducing NO_x emissions in the 1988 fitness assessment. (PPF ¶ 174; DPF App. 1, ¶ 174.)

249. When the fitness assessment was completed in 1988, the condition of Unit 2 was similar to the condition of Unit 1. (PPF ¶ 175; DPF App. 1, ¶ 175.)

250. In 1991, Allegheny's technical staff recommended a rehabilitation project of Unit 1 which would cost an estimated $31,000,000. (PPF ¶ 176; DPF App. 1, ¶ 176.)

251. The purposes of the Unit 1 project were to reduce maintenance costs, reduce the number and cost of start-ups, improve the availability of the boilers, improve boiler efficiency, reduce the amount of unburned carbon, and reduce NO_x emissions. (PPF ¶ 177; DPF App. 1, ¶ 177.)

252. Allegheny also decided to undertake a similar project for Unit 2. (PPF ¶ 178; DPF App. 1, ¶ 178.)

253. The purposes of the Unit 2 project were to reduce maintenance costs, reduce the number and cost of start-ups, improve the availability of the boilers, improve boiler efficiency, reduce the amount of unburned carbon, and reduce NO_x emissions. (PPF ¶ 179; DPF App. 1, ¶ 179.)

254. The Unit 2 project was performed during a major outage in 1994. (PPF ¶ 180; DPF App. 1, ¶ 180.)

255. The Unit 1 project was performed during a seven-month outage in 1995. (PPF ¶ 181; DPF App. 1, ¶ 181.)

256. The following eighteen components were replaced or upgraded during the Unit 1 project: (1) boiler structure; (2) draft plant components; (3) superheater area; (4) reheater area; (5) economizer; (6) boiler water wall tubes; (7) wind box; (8) burners, burner management system, and coal pipes; (9) penthouse; (10) vestibule; (11) ash hopper; (12) boundary and curtain air system; (13) over-fire air system; (14) soot blowers; (15) spray water systems; (16) boiler safety valves; (17) boiler controls; and (18) damper drives for the induced draft fans and forced draft fans. (PPF ¶ 184; DPF App. 1, ¶ 184.)

257. The same components were replaced in the Unit 2 project. (PPF ¶ 186; DPF App. 1, ¶ 186.) In addition, during the Unit 2 project, Allegheny replaced some of the downcomer tubes. (PPF ¶ 187; DPF App. 1, ¶ 187.)

258. Allegheny changed the boiler support systems in the Armstrong projects. (PPF ¶ 189; DPF App. 1, ¶ 189.)

259. The cost of the Unit 1 project was $52,431,805. (PPF ¶ 192; DPF App. 1, ¶ 192.)

260. The cost of the Unit 2 project was $53,302,358. (PPF ¶ 193; DPF App. 1, ¶ 193.)

261. The original cost for the Unit 1 boiler was $50,921,213. The original cost for the Unit 2 boiler was $34,819,598. (PPF ¶ 209; DPF App. 1, ¶ 209.)

262. In a memorandum dated July 6, 1993, Allegheny engineer Jeffery Mooney concluded that the Armstrong projects did not meet the requirements for reconstruction under federal NSPS regulations. (PPF ¶ 247; DPF App. 1, ¶ 247.)

263. At all relevant times since the completion of the Unit 1 project in 1995, SO_2 emissions from Unit 1 have exceeded the NSPS limit of 1.20 lb/MMBTU set forth in 40 C.F.R. § 60.43Da. (Additional Joint Stipulations—Liability Phase ¶ 1, ECF No. 431.)

264. At all relevant times since the completion of the Unit 2 project in 1994, SO_2 emissions from Unit 2 have exceeded the NSPS limit of 1.20 lb/MMBTU set forth in 40 C.F.R. § 60.43Da. (*Id.* ¶ 2.)

265. Since Allegheny completed the projects, SO_2 emissions at both Units have typically exceeded 1.20 lb/MMBTU by 200 to 250 percent. (PPF ¶ 265; DPF App. 1, ¶ 265.)

266. Allegheny did not submit a permit application to Pennsylvania DEP to inform it about all the activities included in the Unit 1 and 2 projects or to seek approval to undertake the projects. (PPF ¶ 266; DPF App. 1, ¶ 266.)

267. Allegheny did not operate Unit 1 at Armstrong subject to BAT emission limitations after the completion of the project. (PPF ¶ 269; DPF App. 1, ¶ 269.)

268. Allegheny did not operate Unit 2 at Armstrong subject to BAT emission limitations after completion of the project. (PPF ¶ 271; DPF App. 1, ¶ 271.)

2. *NSPS at Armstrong*

269. Plaintiffs presented the expert testimony of Ranajit Sahu ("Sahu") and Hugh Larkin ("Larkin") with respect to the cost of a comparable new boiler for the Armstrong units.

270. Plaintiffs presented no vendor cost estimates for new facility construction at the time of the Armstrong projects. (Trial Tr. day 1, 161:18–162:1, ECF No. 436.)

271. Sahu and Larkin instead relied on the existing Armstrong units' original construction costs from the 1950s in opining about the cost of a comparable entirely new facility. (*Id.* at 161:24–162:1, 184:20–185:5.)

272. Rather than obtaining vendor estimates for the amount that would be charged to construct a new facility at the time of the projects, Larkin converted the original 1950s construction costs into 1994 dollars for Unit 2 and 1995 dollars for Unit 1 based upon a utility industry inflation index. (*Id.* at 189:18–191:4.)

273. Neither of plaintiffs' experts had previously used this approach in prior NSPS reconstruction analyses. (*Id.* at 162:8-10 (Sahu); Trial Tr. day 2, 43:22–24, 51:16–19, ECF No. 433 (Larkin).)

274. Prior to this case, Larkin had never performed any kind of NSPS reconstruction analysis or estimated the cost of a new boiler. (Trial Tr. day 2, 43:25–44:5, 50:20–23, ECF No. 433.)

275. Prior to this case Sahu had never done an NSPS reconstruction analysis for a coal-fired electricity generating unit or testified about NSPS reconstruction issues. (Trial Tr. day 1, 132:14–21, ECF No. 436.)

276. Larkin admitted that if the original cost basis is not the correct approach to estimate reconstruction, then the Armstrong projects did not violate the NSPS 50 percent rule. (Trial Tr. day 2, 47:14–48:12, ECF No. 433.)

277. Allegheny presented the expert testimony of Golden regarding the cost of a comparable new boiler.

278. To determine the cost of a comparable entirely new facility, Golden used a cost estimating package from the Electric Power Research Institute ("EPRI") called the "Technical Assessment Guide" ("TAG"). (Trial Tr. day 8, 83:21–84:7, ECF No. 449.)

279. The EPRI TAG methodology was available to Allegheny at the time of the Armstrong projects and was well known within the industry. (*Id.* at 83:24–84:7.)

280. Golden used the following methodology to estimate the cost of a generating unit:

   (a) He chose the appropriate EPRI cost estimate based upon the parameters in the TAG most similar to the Armstrong units. (*Id.* at 84:20–85:13.)

   (b) He made adjustments for the unit size. (*Id.* at 90:17–91:13.)

   (c) He made adjustments for the in-service date using an appropriate representation for inflationary effects. (*Id.* at 91:13–17.)

281. Golden used EPA guidance to estimate which portion of the total unit should be considered within the estimate of the cost of a comparable entirely new facility. (*Id.* at 85:19–86:7.)

282. Golden's cost estimate was conservative because the estimate did not include the cost of the boiler feed pump, boiler feed pump drive, feedwater heater, and

associated piping, which are included in the cost of new facilities under the EPA's guidance. (*Id.* at 85:22–87:4.)

283. Golden estimated the cost of comparable new facilities to be $672 per kilowatt for Armstrong Unit 1 (in 1995 dollars) and $659 per kilowatt for Armstrong Unit 2 (in 1994 dollars). (*Id.* at 92:3–6.)

284. Golden estimated the cost of the projects to be $298 per kilowatt for Armstrong Unit 1 (in 1995 dollars) and $303 per kilowatt for Armstrong Unit 2 (in 1994 dollars). (Defs.' Tr. Ex. 1879.)

285. Based upon Golden's testimony, neither the Armstrong Unit 1 or Unit 2 projects exceeded 50 percent of the cost of a comparable new facility. (Trial Tr. day 8, 93:1–3, ECF No. 449.)

286. At the time of the Armstrong projects, Allegheny knew those projects did not equal 50 percent of the cost of a new plant. (Trial Tr. day 5, 173:18–22, ECF No. 438; Trial Tr. day 6, 163:12–18, ECF No. 439.)

G. Facts Relevant to the Statute of Limitations

287. Allegheny had an open relationship with Pennsylvania DEP, and Pennsylvania DEP never had any problems with Allegheny. (Trial Tr. day 6, 149:22–150:21, ECF No. 439; Trial Tr. day 7, 24:20–23, 90:2–3, ECF No. 448.)

288. Allegheny had frequent discussions with Pennsylvania DEP regarding Allegheny's ongoing activities. (Trial Tr. day 6, 149:22–152:20, ECF No. 439.)

289. Allegheny advised Pennsylvania DEP that its representatives had a standing offer to visit Allegheny's plants during outages. (*Id.* at 151:4–12, 152:1–4.)

290. Pennsylvania DEP was free to ask Allegheny any questions, and Allegheny would always provide information in response. (Trial Tr. day 2, 149:12–150:11, ECF No. 433; Trial Tr. day 6, 151:19–25, ECF No. 436; Trial Tr. day 7, 24:24–25:3, ECF No. 448.)

291. Allegheny always provided all information requested by Pennsylvania DEP. (Trial Tr. day 2, 150:12–19, ECF No. 433; Trial Tr. day 7, 44:13–45:5, ECF No. 448.)

292. Allegheny did not apply for or obtain a preconstruction permit for the Armstrong Unit 1 project. (PPF ¶ 757; DPF App. 1, ¶ 757.)

293. Allegheny did not apply for or obtain a preconstruction permit for the Armstrong Unit 2 project. (PPF ¶ 758; DPF App. 1, ¶ 758.)

294. Allegheny submitted a Title V permit application to Pennsylvania DEP for Armstrong in July 1995. (PPF ¶ 819; DPF App. 1, ¶ 819.)

295. The Title V permit application for Armstrong did not disclose the Armstrong projects. (PPF ¶ 820; DPF App. 1, ¶ 820.)

296. Allegheny certified that its Armstrong Title V permit application was true, accurate, and complete. (PPF ¶ 821; DPF App. 1, ¶ 821.)

297. Pennsylvania DEP air quality field inspector Chad Rittle conducted an inspection of Armstrong on September 22, 1995, during the outage for the Armstrong Unit 1 project. (PPF ¶ 840; DPF App. 1, ¶ 840.)

298. Pennsylvania DEP inspector Bruce Fry ("Fry") noted on one of his inspection visits to Armstrong that the plant was replacing preheaters, which he described as a "major undertaking." (Fry Dep. 36:35–37:9, Dec. 12, 2006.) Fry spoke to contractors, but he did not personally observe the construction inside the plant. (*Id.*)

299. Pennsylvania DEP issued the Title V permit for Armstrong in July 2001. (PPF ¶ 822; DPF App. 1, ¶ 822.)

300. Allegheny did not apply for or obtain a preconstruction permit for the Hatfield Unit 1 lower slope project. (PPF ¶ 761; DPF App. 1, ¶ 761.)

301. Allegheny did not apply for or obtain a preconstruction permit for the Hatfield Unit 1 secondary superheater outlet header project. (PPF ¶ 769; DPF App. 1, ¶ 769.)

302. Allegheny did not apply for or obtain a preconstruction permit for the Hatfield Unit 2 lower slope project. (PPF ¶ 763; DPF App. 1, ¶ 763.)

303. Allegheny did not apply for or obtain a preconstruction permit for the Hatfield Unit 2 pendant reheater project. (PPF ¶ 767; DPF App. 1, ¶ 767.)

304. Allegheny did not apply for or obtain a preconstruction permit for the Hatfield Unit 3 lower slope project. (PPF ¶ 765; DPF App. 1, ¶ 765.)

305. Allegheny submitted a Title V permit application to Pennsylvania DEP for Hatfield in July 1995. (PPF ¶ 823; DPF App. 1, ¶ 823.)

306. The Title V permit application for Hatfield did not disclose the Hatfield projects. (PPF ¶ 824; DPF App. 1, ¶ 824.)

307. Allegheny certified that its Hatfield Title V permit application was true, accurate, and complete. (PPF ¶ 825; DPF App. 1, ¶ 825.)

308. Pennsylvania DEP air quality inspector Bill Frioni conducted an inspection of Hatfield on September 30, 1996, during the outage for the Hatfield Unit 3 lower slope project. (PPF ¶ 847; DPF App. 1, ¶ 847.)

309. Fry conducted a gas audit of the continuous emission monitors at Hatfield on November 2, 1999, during the Hatfield Unit 2 lower slope project. (PPF ¶ 850; DPF App. 1, ¶ 850.)

310. Allegheny did not apply for or obtain a preconstruction permit for the Mitchell Unit 3 lower slope project. (PPF ¶ 771; DPF App. 1, ¶ 771.)

311. Allegheny submitted a Title V permit application to Pennsylvania DEP for Mitchell in July 1995. (PPF ¶ 827; DPF App. 1, ¶ 827.)

312. The Mitchell Title V permit application did not disclose the Mitchell projects. (PPF ¶ 828; DPF App. 1, ¶ 828.)

313. Allegheny certified that its Mitchell Title V permit was true, accurate, and complete. (PPF ¶ 829; DPF App. 1, ¶ 829.)

314. Pennsylvania DEP issued the Title V permits for Mitchell in March 2002. (PPF ¶ 830; DPF App. 1, ¶ 830.)

315. An inspector could not tell, just by looking at the activity inside a power plant, whether or not a PSD permit will be required. (Trial Tr. day 2, 100:2–11, ECF No. 433.)

316. Plaintiffs' expert Mark Wayner ("Wayner") acknowledged that Pennsylvania DEP air quality field inspectors were charged with determining whether Allegheny's coal-fired power plants were in compliance with existing permits. (*Id.* at 88:12–21.)

317. Wanyer noted that it is the responsibility of the applicant to submit and obtain preconstruction approval from Pennsylvania DEP. (*Id.* at 97:22–98:2.)

II. Conclusions of Law

A. Preliminary Issues

1. Evidentiary Issues

318. The court considered the parties' various evidentiary objections presented in their post-trial briefing. (ECF Nos. 445, 458, 459, 482, 485).

319. The court notes that the Federal Rules of Evidence favor admissibility, especially in a bench trial. In a nonjury case, "it is almost impossible" for a court to commit reversible error by admitting evidence. 11 Charles Alan Wright, Arthur R. Miller & Mary Kay Kane, Federal Practice and Procedure § 2885 (3d ed. 2012).

320. Allegheny originally objected to fourteen documents plaintiffs seek to admit into evidence. (ECF No. 445.) Allegheny subsequently withdrew its objections

to PTX Nos. 144, 208, 921, 922, 1859, and 1897. (ECF No. 466, at 1 n.1.) Accordingly, those documents are admitted.

321. Allegheny objects to the remaining documents plaintiffs seek to admit on the basis that they are hearsay. With respect to PTX Nos. 125, 170, and 171, the objections are sustained. PTX No. 1298 is the 40th edition of *Steam: Its Generation and Use*, published in 1992. This book is clearly hearsay. It is, however, a technical guide to the kind of coal-fired boilers at issue in this case. It will be admitted on the basis that it has "circumstantial guarantees of trustworthiness" equivalent to the hearsay exceptions in Rules 803 and 804 of the Federal Rules of Evidence. FED. R. EVID. 807(a)(1). The court notes that this textbook was adopted, by stipulation of the parties, as the authoritative source of information on steam generation in another new source review case. *United States v. Ohio Edison Co.*, 276 F. Supp. 2d 829, 839 n.6 (S.D. Ohio 2003). PTX Nos. 1300 and 1580 are admitted under the ancient documents exception to the hearsay rule. FED. R. EVID. 803(16). Allegheny's remaining objection is to PTX No. 1936, a textbook. Plaintiffs claim this textbook is not being offered for the truth of the matter asserted, but is being offered to establish what Allegheny understood were the appropriate ways to calculate increases in emissions. This exhibit is clearly hearsay to which no exception applies. It will, therefore, not be admitted.

322. Plaintiffs object to documents related to the testimony of Allegheny's RMRR expert, Golden. Specifically, plaintiffs object to DTX Nos. 723, 851, 963, 964, 997, 1220, 1224, 1225, 1226, 1292, 1448, 1716, 1717, 1735, 1737, 1757, 1769, 1772, 1774, 1776, 1778, 1792, and 1828. (ECF No. 459.) Plaintiffs objected to an additional twenty documents which Allegheny agreed to withdraw. (ECF No. 469, at 2 n.1.) The court already heard and overruled these objections. (Trial Tr. day 8, 9:23–25; 7:6–9:22, ECF No. 449.) As the court noted, these exhibits, all of which were relied on by Golden to form his opinion, are admissible.

2. *Mootness*

323. Allegheny argues that its post-trial closure of the plants at issue renders the claims for injunctive relief moot.

324. Mootness arises where "'changes in circumstances that prevailed at the beginning of the litigation ... have forestalled any occasion for meaningful relief.'" *Int'l Bhd. of Boilermakers, Iron Ship Builders, Blacksmiths, Forgers & Helpers v. Kelly*, 815 F.2d 912, 915 (3d Cir. 1987) (quoting *Jersey Cent. Power & Light Co. v. New Jersey*, 772 F.2d 35, 39 (3d Cir. 1985)).

325. The standard announced by the Supreme Court "for determining whether a case has been mooted by the defendant's voluntary conduct is stringent: 'A case might become moot if subsequent events made it absolutely clear that the allegedly wrongful behavior could not reasonably be expected to recur.'" *Friends of the Earth, Inc. v. Laidlaw Envtl. Servs., Inc.*, 528 U.S. 167, 189 (2000) (quoting *United States v. Concentrated Phosphate Export Ass'n, Inc.*, 393 U.S. 199, 203 (1968)).

326. "[T]he 'heavy burden of persua[ding]' the court that the challenged conduct cannot reasonably be expected to start up again lies with the party asserting mootness." *Id.* (quoting *Concentrated Phosphate*, 393 U.S. at 203) (alteration in original).

327. Allegheny can preserve its right to reactivate the plant under existing permit conditions by making submissions to Pennsylvania DEP within the first year of inactivity.

328. If Allegheny does so, it can reactivate the plants under the terms of the existing Title V permits. 25 Pa. Code § 127.215(a)(1).

329. Armstrong was shut down on September 1, 2012. More than a year has passed without Allegheny seeking to reactivate the existing Title V permits. Accordingly, the challenged conduct cannot reasonably be expected to start up again.

330. Plaintiffs concede as much. (Pls.' Supp. Br. Resp. 18 n.4, ECF No. 500; Pls.' Supp. Mem. 9–10, ECF No. 509 (conceding that the only remaining injunctive claims concern Hatfield and Mitchell).)

331. Hatfield and Mitchell were shut down on October 9, 2013. (Second Notice of Subsequent Developments Ex. A, ECF No. 516.)

332. Thus, Allegheny retains the option to submit the reactivation materials for up to a year after October 9, 2013.

333. The court concludes that Allegheny has not established that the violations alleged at Hatfield and Mitchell cannot recur. In short, Allegheny failed to establish that the plant closures are permanent.

334. Accordingly, the court finds that, at this juncture, the case is not moot with respect to the plaintiffs' claims for injunctive relief at Hatfield and Mitchell.

3. *Statute of Limitations*

335. The CAA contains no statute of limitations. The parties agreed that the five-year statute of limitations contained in 28 U.S.C. § 2462 applies to the CAA. (Summ. J. Op. 10, ECF No. 380.)

336. The APCA has a seven-year statute of limitations. 35 Pa. Stat. § 4010.3. It provides that each day of noncompliance constitutes a continuing violation. 35 Pa. Stat. § 4009.3.

337. The complaint was filed in 2005, more than seven years after the projects at issue were performed, with the exception of the Hatfield Unit 2 lower slope project, which was performed in 1999.

338. The court ruled that the statute of limitations does not bar plaintiffs' federal claims seeking equitable relief or the Pennsylvania claims. (Summ. J. Op. 8 n.2, 9.)

339. With respect to the Pennsylvania claims, the court held that the Pennsylvania claims were not time barred by reason of the continuing violation provision of the APCA. (Report & Rec. 36, ECF No. 220; Summ. J. Op. 10.)

340. After considering the decision of the Court of Appeals for the Third Circuit in *United States v. EME Homer City Generation, L.P.*, 727 F.3d 274 (3d Cir. 2013), the court reverses its earlier ruling and now holds that the Pennsylvania PSD claims for damages are time barred, except for count 18 as it relates to the Hatfield Unit 2 lower slope project.

341. In *EME Homer City*, the court of appeals concluded that the under the CAA, the PSD program prohibits construction and modification without the proper permit and pollution controls, but does not provide for a continuing violation for each day after an illegal modification:

> We agree with the unanimous view of the other courts of appeals that have addressed this question. The PSD program's plain text requires the answer be "no." Under 42 U.S.C. § 7475(a), "[n]o major emitting facility … may be constructed [or modified] … unless" it meets various PSD requirements, including obtaining a PSD permit and installing BACT-based emission controls. That provision prohibits "construct[ing]" a facility without obtaining a PSD permit or using BACT, and while "construction" is defined to include "modifications," *see* 42 U.S.C. § 7479(2)(C), it does not include "operation." And § 7475(a) does not exactly try to hide its exclusive link to construction and modification: after all, the section is titled "Preconstruction Requirements"—not "Preconstruction and Operational Requirements." In short, "[n]othing in the text of § 7475 even hints at the possibility that a fresh violation occurs every day until the end of the universe if an owner that lacks a construction permit operates a completed facility." *United States v. Midwest Generation, LLC*, 720 F.3d 644, 647 (7th Cir. 2013); *see also Sierra Club v. Otter Tail Power Co.*, 615 F.3d 1008, 1015 (8th Cir. 2010) (agreeing with the Eleventh Circuit that operating a modified facility without a PSD permit is simply "not articulated as a basis for a violation" (quoting *Nat'l Parks & Conservation Ass'n v. Tenn. Valley Auth.* (*Nat'l Parks 11th Cir.*), 502 F.3d 1316, 1323 (11th Cir. 2007))). Instead, "[t]he

> violation is complete when construction [or modification] commences without a permit in hand." *Midwest Generation, LLC*, 720 F.3d at 647.

EME Homer City, 727 F.3d at 284–85 (footnote omitted).

342. The court of appeals rejected the EPA's argument that PSD requirements under Pennsylvania law provide for continuing violations for operating a modified plant:

> Aside from the federal statutes and regulations, the EPA turns to the Pennsylvania SIP as a source of freestanding PSD requirements. But Pennsylvania's SIP merely parallels the Clean Air Act's PSD requirements and does nothing to transform the PSD permitting requirements into operating conditions. For example, 25 Pa. Code § 127.11 prohibits a person from "caus[ing] or permit[ting] *the construction or modification*"—not operation—"of an air contamination source" unless the Pennsylvania Department of Environmental Protection has approved the source's plan for construction or modification. And like the EPA's own regulation at 40 C.F.R. § 52.21(r)(*l*), the Pennsylvania SIP requires sources to operate in compliance with their application for plan approval and "the conditions in the plan approval issued by the Department"—which does not prohibit operation without an approved plan (or PSD permit). 25 Pa. Code § 127.25. To be sure, the Pennsylvania SIP does authorize the Department to "issue an operating permit to an existing and operating source that is out of compliance with … the Clean Air Act or the regulations thereunder." 25 Pa. Code § 127.445(a). But that provision, which *allows the Department* to issue corrective operating permits for sources lacking required PSD permits, hardly *requires the owners and operators* to apply for PSD permits as a condition of operation.

EME Homer City, 727 F.3d at 290 (footnote omitted).

343. Plaintiffs argue that *EME Homer City* is distinguishable because there was a change in ownership between the time of the modifications and the time the suit was brought. (ECF No. 509, at 3.) The court concludes, however, that the court of appeals' holding—that operation of a modified plant that failed to

comply with PSD requirements does not constitute a continuing violation—is unaffected by this factual difference.

344. The court concludes that the analysis of the court of appeals in *EME Homer City* applies to this case. The ACPA provides that "[e]ach day of continued violation … shall constitute a separate offense and violation." 35 Pa. Stat. § 4009.3. Since only the construction or modification of a facility can constitute a PSD violation under both federal and state law, and since the alleged modifications in violation of PSD requirements occurred more than five years (for CAA claims) and seven years (for ACPA claims) before this case was brought, both the federal and Pennsylvania PSD claims for damages are barred by the statute of limitations.

345. Plaintiffs argue that, under the law of the case doctrine, the court should not reverse its ruling that Pennsylvania claims are not time barred. (ECF No. 509, at 8; ECF No. 500, at 13.) The law of the case doctrine promotes "finality and judicial economy" by limiting courts' discretion to reconsider issues previously decided in a lawsuit. *Pub. Interest Research Grp. of N.J., Inc. v. Magnesium Elektron, Inc.*, 123 F.3d 111, 116 (3d Cir. 1997). The doctrine does not curtail a court's power to revisit prior decisions in "extraordinary circumstances," including where there is (1) new evidence available, (2) a supervening change in the law, or (3) an earlier decision that is "clearly erroneous and would create manifest injustice." *Id.* at 166–17. The court of appeals' ruling, as a matter of first impression, that failure to follow PSD requirements is not a continuing violation constitutes "supervening legal authority." *W.R. Grace & Co. v. Chakarian (In re W.R. Grace & Co.)*, 591 F.3d 164, 174 (3d Cir. 2009). Thus, the court's previous ruling is appropriately reversed in light of the holding of the Court of Appeals for the Third Circuit in *EME Homer City*.

346. The court's earlier ruling that the statute of limitations does not bar plaintiffs' claims for injunctive relief is not affected by *EME Homer City*, and that ruling remains undisturbed. *See EME Homer City*, 727 F.3d at 289 ("If the EPA does

not object within five years of the completion of a facility's modification, then it loses the right to seek civil penalties under the statute of limitations, but can still obtain an injunction requiring the owner or operator to comply with the PSD requirements.").

347. The court held that the statute of limitations may be equitably tolled. (Summ. J. Op. 12, ECF No. 380 (citing *Ramadan v. Chase Manhattan Corp.*, 156 F.3d 499, 504 (3d Cir. 1998)).) The court of appeals recognized the potential applicability of equitable tolling to CAA claims. *EME Homer Generation*, 727 F.3d at 291 n.18.

348. The court noted that a statute of limitations may be equitably tolled when "'a defendant actively misleads a plaintiff with respect to [his/her] cause of action.'" (Summ. J. Op. 12 (quoting *Lake v. Arnold*, 232 F.3d 360, 369 n.9 (3d Cir. 2000)).)

349. A statute of limitations may be equitably tolled upon a showing that a defendant's "acts or omissions … lulled the plaintiff into foregoing prompt attempts to vindicate his rights." *Bonham v. Dresser*, 569 F.2d 187, 193 (3d Cir. 1978) (addressing the 180-day filing requirement of the Age Discrimination in Employment Act, which is "in the nature of a statute of limitations").

350. For the statute of limitations to be equitably tolled, a plaintiff must show that it exercised due diligence. *Santos ex rel. Beato v. United States*, 559 F.3d 189, 197 (3d Cir. 2009).

351. The evidence adduced at trial indicates that Allegheny had an open relationship with Pennsylvania DEP, and Pennsylvania DEP never had any problems with Allegheny. (Trial Tr. day 6, 149:22–150:21, ECF No. 439; Trial Tr. day 7, 24:20–23, 90:2–3, ECF No. 448.)

352. Allegheny had frequent discussions with Pennsylvania DEP regarding Allegheny's ongoing activities. (Trial Tr. day 6, 149:22–152:20, ECF No. 439.)

353. Allegheny advised Pennsylvania DEP that its representatives had a standing offer to visit Allegheny's plants during outages. (*Id.* at 151:4–12, 152:1–4.)

354. Pennsylvania DEP was free to ask Allegheny any questions, and Allegheny would always provide information in response. (Trial Tr. day 2, 149:12–150:11, ECF No. 433; Trial Tr. day 6, 151:19–25, ECF No. 439; Trial Tr. day 7, 24:24–25:3, ECF No. 448.)

355. Allegheny always provided all information requested by Pennsylvania DEP. (Trial Tr. day 2, 150:12–19, ECF No. 433; Trial Tr. day 7, 44:13–45:5, ECF No. 448.)

356. Pennsylvania DEP employees inspected Allegheny's plants while the projects at issue were in progress.

357. The record does not support a finding that Allegheny actively misled Pennsylvania DEP.

358. Even if Allegheny actively misled Pennsylvania DEP, Pennsylvania DEP failed to adduce sufficient evidence to show it exercised due diligence.

359. The States of Connecticut, Maryland, New Jersey, and New York do not invoke equitable tolling because the allegedly misleading statements were only made to Pennsylvania DEP. (Pls.' Post Trial Mem. 201 n.67, ECF No. 463.)

360. Accordingly, equitable tolling does not apply. Plaintiffs' PSD claims for civil penalties under federal and Pennsylvania law are time barred, except for the claim under Pennsylvania law related to the Hatfield Unit 2 lower slope project (count 18).

361. Because the claims for civil penalties are timed barred and, as addressed above, the claims for injunctive relief at Armstrong are moot, the court finds in favor of Allegheny with respect to counts 1, 2, 7, and 8 for alleged PSD violations at Armstrong.

4. *Subject-Matter Jurisdiction over Title V Claims*[2]

362. Plaintiffs allege that Allegheny submitted incomplete applications for Title V operating permits for Armstrong (counts 13 and 14), Hatfield (counts 21 and 22), and Mitchell (counts 25 and 26).

363. In *EME Homer City*, the Court of Appeals for the Third Circuit concluded that the district court lacked jurisdiction to entertain plaintiff EPA's claims alleging Title V permitting violations. The court concluded that judicial review of the EPA's decision not to object to the issuance of a Title V permit is vested directly in the court of appeals for the appropriate circuit. *EME Homer City*, 727 F.3d at 297 (citing 42 U.S.C. § 7607). Congress did not authorize actions in district court for claims that a regulated entity violated Title V by submitting incomplete applications. *Id.* at 299.

364. Plaintiffs argue that *EME Homer City* is distinguishable because the instant case arises under the citizen suit provision of the CAA. (ECF No. 509, at 6.) Plaintiffs assert that Congress expressly authorized district courts to hear claims that a regulated entity violated Title V. (*Id.* (citing 42 U.S.C. § 7604(a)(1).) Plaintiffs assert that the court of appeals did not "acknowledge, let alone apply, this plain statutory authority that authorizes plaintiffs' suit here." (*Id.* at 7.)

365. The original plaintiff in *EME Homer City* was the United States, but several states intervened under the citizen suit provision, 42 U.S.C. § 7604. The court of appeals dismissed the Title V claims of both the EPA and the states for lack of jurisdiction. *EME Homer City*, 727 F.3d at 300 ("[T]he District Court lacked jurisdiction over the EPA's Title V claims."); *see id.* at 277 n.1 ("For readability, 'the EPA' refers to both the EPA and the states unless otherwise specified.").

2 "The objection that a federal court lacks subject-matter jurisdiction may be raised by a party, or by a court on its own initiative, at any stage in the litigation, even after trial and the entry of judgment." *Arbaugh v. Y & H Corp.*, 546 U.S. 500, 506 (2006) (citation omitted).

366. Plaintiffs' argument amounts to a contention that *EME Homer City* was wrongly decided with respect to district courts' jurisdiction over Title V claims under the citizen suit provision of the CAA. Whatever merit plaintiffs' argument has, this holding constitutes binding precedent upon this court. The Title V claims are therefore dismissed for lack of subject-matter jurisdiction.

B. Clean Air Act and Pennsylvania Pollution Control Act

1. Generally

367. In 1970, Congress amended the Clean Air Act and directed the EPA to set nationwide air quality standards for a number of air pollutants, including SO_2, NO_X, and ozone. Clean Air Amendments of 1970, Pub. L. No. 91-604, § 4(a), 84 Stat. 1676, 1679 (codified as amended at 42 U.S.C. § 7409).

368. These standards are known as the National Ambient Air Quality Standards ("NAAQS").

369. Based upon the NAAQS, the EPA classifies each county across the nation as (1) an attainment area, if the level of the pollutant in the air is low enough to meet the standard; (2) a nonattainment area, if the level of the pollutant exceeds the standard; or (3) uncategorizable. 42 U.S.C. § 7407(d)(1)(A), (B).

370. Under the Clean Air Act, a state implementation plan ("SIP") is the set of air pollution regulations or other requirements that a state promulgates to achieve and maintain compliance with the NAAQS. 42 U.S.C. § 7410(a)(1).

371. A SIP, including any subsequent revisions, is subject to EPA approval. 42 U.S.C. § 7410(a)(3), (5).

372. Once approved by the EPA, the SIP has the force of federal law. 42 U.S.C. § 7413(a).

373. In 1977, Congress enacted the PSD program and the nonattainment NSR program. These programs are collectively known as "new source review." Clean

Air Act Amendments of 1977, Pub. L. No 95-95, §§ 127, 129, 91 Stat. 685, 731–42, 745–51 (codified as amended at 42 U.S.C. §§ 7470–7479, 7501–7508).

374. PSD applies to pollution in attainment or unclassifiable areas. 42 U.S.C. § 7471.

375. PSD includes a preconstruction permitting program that subjected covered facilities in those areas to stringent air pollution control requirements known as "best available control technology" ("BACT"). 42 U.S.C. § 7475(a)(1), (4).

376. A utility company would be subject to these requirements if it undertook "construction" which the Clean Air Act defines as including "modification." 42 U.S.C. § 7479(2)(C).

377. A "modification" is "any physical change in, or change in the method of operation of, a stationary source which increases the amount of any air pollutant emitted by such source or which results in the emission of any air pollutant not previously emitted." 42 U.S.C. § 7411(a)(4).

378. As applicable to this case, the EPA issued PSD regulations in 1978 and amended those regulations in 1980 and 1992. 43 Fed. Reg. 26,403 (June 19, 1978) (codified at 40 C.F.R. §52.21); 45 Fed. Reg. 52,676 (Aug. 7, 1980) (same); 57 Fed. Reg. 32,314 (July 21, 1992) (same).[3]

379. Under EPA regulations, major stationary sources are subject to PSD requirements if they undergo a "major modification." 40 C.F.R. § 52.21(i)(2).

380. A "major modification" is "any physical change in or change in the method of operation" of a covered plant that "would result in a significant net emissions increase" of certain pollutants. 40 C.F.R. § 52.21(b)(2)(i).

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3 The alleged violations took place between 1993 and 1999. Although the regulations have been subsequently amended, the rules issued July 21, 1992, are the applicable regulations in this case. Accordingly, cites to 40 C.F.R. part 52 are to the 1993 edition.

381. Nonattainment NSR applies to pollution in nonattainment areas. 42 U.S.C. § 7502.

382. The nonattainment NSR regulations also subject certain power plants to the applicable requirements if those plants undergo a "major modification."

383. A major modification under the nonattainment NSR regulations is defined exactly the same way as under the PSD regulations. 40 C.F.R. § 51.165(a)(1)(v)(A).

384. The nonattainment NSR regulations include emission limitations that achieve the "lowest achievable emissions rate" ("LAER"). 40 C.F.R. § 51.165(a)(1)(xiii).

385. LAER is the most stringent emissions limitation under the clean air act. 42 U.S.C. § 7501(3).

386. A SIP must include both the PSD and nonattainment new source review programs. 42 U.S.C. § 7410(a)(2)(C).

387. A SIP may include more stringent requirements than the EPA's requirements. 42 U.S.C. § 7416.

388. Pennsylvania incorporated the federal PSD regulations by reference in its SIP. 25 Pa. Code §§ 127.81–.83.

389. In 1984, the EPA approved Pennsylvania's SIP. Approval of a Revision of the Pennsylvania State Implementation Plan, 49 Fed. Reg. 33,127 (Aug. 21, 1984).

390. Since the Pennsylvania PSD requirements are identical to the federal PSD requirements, violation of the federal PSD regulations by a Pennsylvania power plant is also a violation of Pennsylvania law.

391. Even if there is a modification that increases emissions, these rules are not triggered if the project is RMRR. 40 C.F.R. § 52.21(b)(2)(iii)(*a*). Thus, there is no need to apply for a PSD permit if the change is RMRR.

392. The seminal case addressing the RMRR defense is *Wisconsin Electric Power Co. v. Reilly*, 893 F.2d 901 (7th Cir. 1990) ("*WEPCo*"). The Court of Appeals for the Seventh Circuit identified five factors relevant to the RMRR defense: the project's (1) nature; (2) extent; (3) purpose; (4) frequency; and (5) cost. *Id.* at 910–11.

393. District courts analyzing RMRR apply the five *WEPCo* factors after a case-by-case review. *E.g.*, *United States v. Ala. Power Co.*, 681 F. Supp. 2d 1292, 1312 (N.D. Ala. 2008); *United States v. E. Ky. Power Coop, Inc.*, 498 F. Supp. 2d 976, 993 (E.D. Ky. 2007); *United States v. Ohio Edison Co.*, 276 F. Supp. 2d 829, 858–62 (S.D. Ohio 2003).

394. In reaction to *WEPCo*, the EPA amended the PSD rules and issued clarifying guidance. 57 Fed. Reg. 32,314 (July 21, 1992).

395. There is a split of authority with respect to whether the *WEPCo* factors are analyzed on a "routine in the industry as a whole" standard or a "routine at the specific unit" standard.

396. After examining the relevant case law and EPA guidance, this court previously held that "at trial, we will ... apply the 'routine in the industry' standard to Allegheny's RMRR defense." (Summ. J. Op. 14, ECF No. 380 (adopting Report & Rec. 7–14, ECF No. 220).)

397. Allegheny bears the burden of proof on the RMRR defense. *Ala. Power Co.*, 681 F. Supp. 2d 1292, 1313 (N.D. Ala. 2008); *E. Ky. Power Coop.*, 498 F. Supp. 2d at 994–95; *Ohio Edison Co.*, 276 F. Supp. 2d 829, 856 (S.D. Ohio 2003); *see Berckeley Inv. Grp. v. Colkitt*, 455 F.3d 195, 212 (3d Cir. 2006) (holding that "the burden of proving entitlement to an exemption rests with the party claiming the entitlement.").

2. *PSD Claims*

398. As noted above, the statute of limitations bars plaintiffs' claims for civil penalties, except for the claim with respect to the Hatfield Unit 2 lower slope project under Pennsylvania law (count 18).

399. At this juncture, plaintiffs' claims for injunctive relief at Hatfield and Mitchell are not moot. Accordingly, set forth below is an analysis of plaintiffs' PSD claims.

400. The court concludes that Allegheny satisfied its burden of establishing that the Hatfield and Mitchell projects were RMRR.

401. Based upon the testimony presented, the court finds Allegheny's witnesses, particularly Allegheny's expert Golden, to be entitled to more weight than plaintiffs' witnesses on the issue of what constitutes RMRR.

402. In concluding that the Hatfield and Mitchell projects were RMRR, the court credits the testimony of Golden.

403. Based upon his analysis of utility and OEM data, Golden concluded that the nature, extent, purpose, frequency, and cost of the projects were consistent with routine industry practices.

404. The manner in which Allegheny performed the Hatfield and Mitchell projects was consistent with typical industry component replacement practices. (Trial Tr. day 8, 52:15–57:12, ECF No. 449.)

405. The duration of each outage during which the Hatfield and Mitchell projects were performed falls within the normal range of outage lengths at Allegheny and in the coal-fired power industry. (*Id.* at 54:5–15, 56:8–23.)

406. It is typical in the industry for each individual component replacement project to have its own work order and individual justification, as was done with the Hatfield and Mitchell projects. (*Id.* at 53:4–11.)

407. Golden analyzed the purposes of the Hatfield and Mitchell projects and found them to be similar to the purposes of the typical type of boiler component replacement in the industry. (*Id.* at 39:6–22, 43:9–19.)

408. Golden identified thousands of pressure part replacement projects that cost more than $100,000 at coal-fired power stations in the United States based upon the business records of utility companies and OEM suppliers and concluded that the Hatfield and Mitchell projects were typical of the kind performed frequently in the industry. (*Id.* at 57:13–73:7.)

409. Utility companies in the electric generating industry routinely replace, in whole or in part, high-wear areas in their coal-fired boilers, such as lower slope tube panels. (*Id.* at 44:19–25, 51:23–52:2.)

410. The costs of the Hatfield and Mitchell projects were consistent with routine maintenance, repair, and replacement activities in the industry. (*Id.* at 73:17–79:24.)

411. The court finds that the purposes of the Hatfield and Mitchell projects were not life extension; rather, the purposes were to avoid future forced and planned maintenance outages and reduce maintenance cost.

412. The Hatfield and Mitchell projects cost $2.50 to $12 per kilowatt, well below the normal low-end cost of $100 per kilowatt for utility life extension projects. (*Id.* at 74:14–25, 78:17–79:24.)

413. The EPA determined that the proposed WEPCo Port Washington project was "unprecedented" and not RRMR. Clay Memorandum 3–4. The Hatfield and Mitchell projects, however, cost significantly less, both in absolute terms and in dollars per kilowatt, than the WEPCo project, which cost $70,500,000 ($204 per kilowatt). (*Id.* at 76:8–16, 78:17–79:24, 81:8–22.)

414. A district court found that the 1986 Beckjord Unit 3 project did not qualify for the RRMR exclusion. *United States v. Cinergy Corp.*, 495 F. Supp. 2d 909, 937

(S.D. Ind. 2007). The Hatfield and Mitchell projects, however, cost significantly less, both in absolute terms and in dollars per kilowatt, than the 1986 Beckjord Unit 3 project, which cost $13,000,000 ($183 per kilowatt). (Trial Tr. day 8, 76:8–16, 79:4–9, 81:21–22, ECF No. 449.) Unlike the Hatfield and Mitchell projects, the purpose of the Beckjord project was life extension. *Cinergy Corp.*, 495 F. Supp. 2d at 933.

415. The court was not persuaded by the evidence offered by plaintiffs on this point. Specifically, the court did not give weight to the testimony of plaintiffs' expert, Koppe.

416. The court will enter judgment in favor of Allegheny and against plaintiffs on the Hatfield and Mitchell PSD claims (counts 15, 16, 17, 18, 19, 20, 23, and 24).

3. *Remaining Claims at Armstrong*

417. Plaintiffs asserted three claims for civil penalties for alleged violations at Armstrong: (1) an NSPS claim under federal law (counts 4 and 10) and Pennsylvania law (counts 5 and 11); (2) a nonattainment NSR claim under Pennsylvania law (counts 3 and 9); (3) a BAT claim under Pennsylvania law (counts 6 and 12).

a. NSPS

418. Under the CAA, an electric utility steam generating unit is subject to NSPS regulations if it is a "new source." 42 U.S.C. § 7411. An existing facility that undergoes a "reconstruction" is subject to the regulations. 40 C.F.R. § 60.15(a). A project is an NSPS-triggering reconstruction if (1) the fixed capital cost of the new components exceeds 50 percent of the capital cost that would be required to construct a comparable entirely new facility and (2) it is technologically and economically feasible to meet the standards. 40 C.F.R. § 60.15(b).

419. Pennsylvania adopted and incorporated by reference the federal NSPS regulations into Pennsylvania law. 25 Pa. Code §§ 122.1–.3. Accordingly, any

violation of federal NSPS regulations by a Pennsylvania power plant is a violation of Pennsylvania law.

420. If the cost of the work performed at Armstrong Units 1 and 2 is less than 50 percent of the cost of constructing an entirely new facility, there is no reconstruction and no violation of the NSPS under the CAA or APCA.

421. Allegheny presented the expert testimony of Golden regarding the cost of a comparable new boiler.

422. To determine the cost, Golden used the EPRI TAG methodology, which was available to Allegheny at the time of the Armstrong projects and was well known within the industry. (Trial Tr. day 8, 83:21–84:7, ECF No. 449.)

423. Golden also used EPA guidance to estimate which portion of the total unit should be considered within the estimate of the cost of a comparable entirely new facility. (*Id.* at 85:19–86:7.)

424. The court finds the expert testimony of Golden about the cost of a comparable new facility entitled to weight.

425. The testimonies of plaintiffs' experts Sahu and Larkin about the cost of a comparable new facility are not entitled to weight because their calculations depend upon the original cost of the Armstrong units and an inflation adjustment which does not account for changes in design. The court finds their testimonies not entitled to weight because they failed to define properly the portion of the affected unit to include in their calculations. Their calculations both overstate and understate the relevant costs.

426. Golden testified that the cost of comparable new facility for Armstrong Unit 1 was $672 per kilowatt and the cost of the Armstrong Unit 1 project was $298 per kilowatt, i.e. 45 percent of the cost of a comparable new facility. (*Id.* at 92:3–21.) Golden testified that the cost of comparable new facility for Armstrong Unit 2 was $659 per kilowatt and the cost of the Armstrong Unit 2 project was

$303 per kilowatt, i.e. 46 percent of the cost of a comparable new facility. (*Id.*) The court accepts Golden's methodology, credits his testimony, and concludes that neither the Armstrong Unit 1 project nor the Armstrong Unit 2 project exceeded 50 percent of the cost of a comparable new facility.

427. The court will enter judgment in favor of Allegheny and against plaintiffs on the NSPS claim (counts 4, 5, 10, and 11).

b. Nonattainment NSR

428. The parties agree that plaintiffs must prove that Armstrong projects resulted in the construction of a "new source" to prevail on the nonattainment NSR claim. (ECF No. 463, at 176–77; ECF No. 471, at 20.) New source is defined in relevant part as any source "modified … so that the fixed capital cost of new components exceed 50% of the fixed capital cost that would be required to construct a comparable entirely new source." 25 PA. CODE § 121.1.

429. Because, as described above, the cost of the new components on Armstrong Units 1 and 2 did not exceed 50 percent of the cost of a comparable new source, the court enters judgment in favor of Allegheny and against plaintiffs on the nonattainment NSR claim (counts 3 and 9).

c. BAT

430. Pennsylvania law bars the construction of new sources, as defined in 25 PA. CODE § 121.1, unless the source receives preconstruction approval and meets BAT requirements. 25 PA. CODE § 127.11–.52.

431. The court concludes, as it did on the NSPS and nonattainment NSR claims, that plaintiffs failed to prove that the Armstrong projects were a "new source." As a result, plaintiffs' claims pursuant to BAT (counts 6 and 12) fail as well.

4. Emissions Findings

432. In light of the court's determination about the statute of limitations, mootness, and RMRR issues, there is no need for the court to make findings about emissions and the court makes no emissions findings.

C. Conclusion

433. For the reasons set forth above, the court finds that in favor of Allegheny and against plaintiffs on all claims.

Dated: February 6, 2014

By the court:

/s/Joy Flowers Conti
Joy Flowers Conti
Chief United States District Judge