4.0 Technology-Based Thermal Discharge Limitations

4.1 Introduction

This section presents the basis for EPA's establishment of thermal discharge limitations for BPS based on the Best Available Technology Economically Achievable (BAT), in accordance with CWA §§ 301(b)(2) and 304(b)(2). These sections of the Act govern the development and implementation of BAT effluent limits for toxic and non-conventional pollutants.[1] EPA issued regulations establishing national effluent limitations on the discharge of heat from point sources in the steam electric power generating category (such as BPS) in 1974, but those regulations were set aside by the United States Court of Appeals for the Fourth Circuit in 1976.[2] Therefore, EPA has developed the thermal discharge limitations contained in the new Draft NPDES permit for BPS based on Best Professional Judgment (BPJ) pursuant to CWA § 402(a)(1), 33 U.S.C. 1342(a)(1), and 40 C.F.R. § 125.3(c)(2).[3]

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1 See CWA §§ 301(b)(2) and 304(b)(2), 33 U.S.C. §§ 1321(b)(2) and 1324(b)(2).

2 See Appalachian Power Co. v. Train, 545 F.2d 1351 (4th Cir. 1976) (EPA required to give further consideration to regulations concerning thermal backfit requirements representing degree of effluent reduction attainable by application of BAT, and barring use of new and existing cooling lakes for closed-cycle cooling).

Heat is defined as a "pollutant" under the CWA in CWA § 502(6), 33 U.S.C. § 1362(6).

3 See In the Matter of Public Service Co. of New Hampshire (Seabrook Station, Units 1 and 2), NPDES Appeal No. 76-7, 1977 WL 22370, *6 (E.P.A.), 1 E.A.D. 332 (1977) ("The effect of the remand of the steam electric generating guidelines was ... to require the Agency to determine what is [BAT] for existing sources on a case-by-case basis under Section 402(a)(1)."); In Re Central Hudson Gas & Electric Corp., Decision of General Counsel No. 63, EPA (Jul. 29, 1977), at 376 (after remand of effluent limitations and guidelines for steam electric power plants by Appalachian Power Co., permit issuing authority could use CWA § 402(a)(1) to impose effluent limitations in permits for four steam electric generating stations discharging into Hudson River); Status of Initial Decision of Regional Administration Where Appeal is Pending, General Counsel Opinion, EPA (Jan. 11, 1977), EPA GCO 77-1, at 1 ("[i]n the wake of Appalachian Power, the Agency has the option of either establishing heat limitations for Seabrook on an ad hoc basis under Section 402(a)(1) of the [CWA] or repromulgating the steam electric regulations").

CWA § 304(b)(2) and 40 CFR § 125.3(d)(3) require EPA to take the following factors into account in setting BAT limits: the age of the equipment and facilities involved; the manufacturing processes used; the engineering aspects of the application of recommended control technologies, including process changes and in-plant controls; non-water quality environmental impacts, including energy requirements; cost; and such other factors as EPA deems appropriate.[4] This section of this development document addresses these BAT-related factors as well as the 40 C.F.R. § 125.3 requirements for developing a BPJ based decision. Finally, this section sets forth the technology-based discharge limits that are mandated by the results of this BAT Determination.

4.2 Legal Requirements and Context

4.2.1 Overview

The regulations and case law governing EPA's development and implementation of BAT limits under the CWA should be construed with Congress's overarching statutory purposes in mind. As the United States Supreme Court has explained,

> [t]he Federal Water Pollution Control Act, commonly known as the Clean Water Act, 86 Stat. 816, as amended, 33 U.S.C. § 1251 et seq., is a comprehensive water quality statute designed to "restore and maintain the chemical, physical, and biological integrity of the Nation's waters." § 1251(a). The Act also seeks to attain "water quality which provides for the protection and propagation of fish, shellfish, and wildlife." § 1251(a)(2).[5]

To accomplish these purposes, the CWA prohibits the discharge of pollutants to waters of the United States without a NPDES permit unless otherwise authorized. The NPDES permit is the mechanism used to implement effluent limitations and other requirements such as monitoring and reporting. When developing effluent limits for a NPDES permit, a permit writer must consider both limits based on the technology available to treat the pollutants (technology-based limits), and limits that are protective of the designated uses of the receiving water (water quality-based limits).

With regard to technology-based limits, the CWA requires that all discharges at a minimum meet effluent limitations based on the technological capability of dischargers to control pollutants in

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4 See CWA § 304(b)(2)(B), 33 U.S.C. § 1314(b)(2)(B); 40 CFR § 125.3(d)(3).

5 PUD No. 1 of Jefferson County v. Washington Department of Ecology, 511 U.S. 700, 704 (1994).

their discharge. The Act directs EPA not merely to promulgate uniform national effluent limitation guidelines (ELGs) for categories of point sources discharging pollutants into waters of the United States, but progressively to institute more stringent effluent limits. For industrial dischargers, CWA § 301(b)(1)(A) required the application of Best Practicable Control Technology Currently Available (BPT) by July 1, 1977. Section 301(b)(2) requires industrial dischargers now to meet more stringent limits based on Best Conventional Pollutant Control Technology (BCT) for conventional pollutants and BAT for toxic and non-conventional pollutants.[6] Particularly, industrial dischargers were required to meet a March 31, 1989 deadline for complying with BAT limits "which will result in reasonable further progress toward the national goal of eliminating the discharge of all pollutants."[7]

The purpose of setting technology-based effluent limits for industrial dischargers is to establish a minimum level of treatment based on currently available technologies while allowing the use of any available control technique to meet the limits, and thereby fostering the required "reasonable further progress toward the national goal of eliminating the discharge of all pollutants."[8] There are two approaches to developing technology-based limits for industrial dischargers: (1) using EPA-promulgated ELGs, and (2) in the absence of ELGs, applying the permit writer's BPJ on a case-by-case basis. EPA develops ELGs based on the effluent reduction capabilities of identified treatment methods that meet the particular technology standard being applied (i.e., BPT, BCT, BAT or BDT) for specific categories of industrial facilities on a nationwide basis. Under CWA § 402(a)(1), permit writers using BPJ apply the same performance-based approach to specific industrial facilities.[9]

For the BPS NPDES permit, EPA has developed a technology-based limit for thermal discharges using BPJ because there are no ELG's for thermal discharges from facilities in the steam electric power generating point source category.[10] Therefore, the discussion below focuses on setting

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6 See CWA § 301(b), 33 U.S.C. §1311(b); 40 C.F.R. 125.3(a). In addition, CWA § 306, 33 U.S.C. § 1316 requires new sources to meet performance standards based on Best Available Demonstrated Control Technology (BDT).

7 See CWA § 301(b)(2), 33 U.S.C. §1311(b)(2).

8 Permit limits are to be based on water quality standards or other requirements of state law if such limits would be more stringent. See CWA § 301(b)(1)(C), 33 U.S.C. § 1311(b)(1)(C).

9 See U.S. EPA Permit Writers' Manual (EPA-833-B-96-003) (Manual) at p. 70 (1996).

10 See 40 CFR Part 423.

technology standards using BPJ.

4.2.2 Best Professional Judgment-Based Effluent Limits

The courts have repeatedly affirmed EPA's authority to set BAT limits on a case-by-case basis using BPJ.[11] According to one court, such "BPJ limits constitute case-specific determinations of the appropriate technology-based limitations for a particular point source."[12]

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[11] See 40 C.F.R. § 125.3. See also NRDC v. EPA, 863 F.2d 1420, 1424-25 (9th Cir. 1988) (environmental group challenge to general permit containing BPJ-based BAT limits for offshore oil and gas drilling industry point sources in Gulf of Mexico); American Petroleum Inst. v. EPA, 787 F.2d 965, 971-72 (5th Cir. 1986) (industry challenge to two general permits containing BPJ-based BAT limits for offshore oil and gas drilling industry point sources discharging to Alaskan Outer Continental Shelf). See also In re: City of Port St. Joe and Florida Coast Paper Co., NPDES Appeal Nos. 94-8 and 94-9, 1997 EPA App. LEXIS 12 (1997) (city and discharger petition for review of NPDES permit for city publicly owned treatment works); In the Matter of: Rubicon Inc., NPDES Appeal No. 85-10, 1988 EPA App. LEXIS 30, 2 E.A.D. 551 (1988) (discharger petition for review regarding denial of request for evidentiary hearing on NPDES permit); In the Matter of AT&T Teletype Corp., NPDES Appeal No. 85-18, 1986 EPA App. LEXIS 20, 2. E.A.D. 167 (1986) (discharger petition for review regarding denial of request for evidentiary hearing on NPDES permit).

[12] NRDC v. EPA, 859 F.2d 156, 199 (D.C. Cir. 1988) (industry and environmental group challenge to 1979 revisions to NPDES regulations, including ban on backsliding from BPJ limits). This court explained,

> [i]n what EPA characterizes as a 'mini-guideline' process, the permit writer, after full consideration of the factors set forth in section 304(b), 33 U.S.C. § 1314(b), (which are the same factors used in establishing effluent guidelines), establishes the permit conditions 'necessary to carry out the provisions of [the CWA].' § 1342(a)(1). These conditions include the appropriate ... BAT effluent limitations for the particular point source. ... [T]he resultant BPJ limitations are as correct and as statutorily supported as permit limits based upon an effluent limitations guideline.

Id. See also Texas Oil & Gas Ass'n v. EPA, 161 F.3d 923, 929 (5th Cir. 1998) (industry challenge to EPA regulations implementing BPJ-based BAT limits for coastal oil and gas extraction point sources) ("Individual judgments thus take the place of uniform national guidelines, but the technology-based standard remains the same.").

EPA's ability to set permit limits on a case-by-case basis using BPJ is provided by CWA § 402(a)(1), which authorizes the Agency to

> issue a permit for the discharge of any pollutant, or combination of pollutants ... upon condition that such discharge will meet either (A) all applicable requirements under sections 1311, 1312, 1316, 1317, 1318, and 1343 of this title, or (B) prior to the taking of necessary implementing actions relating to all such requirements, such conditions as the Administrator determines are necessary to carry out the provisions of this chapter.[13]

EPA and the courts have interpreted § 402(a)(1) as allowing the imposition of effluent limits on a case-by-case basis using BPJ where EPA has not yet promulgated ELGs for a particular category of point sources.[14] BPJ limits are also appropriate where ELGs are available for a point source category but do not regulate a particular pollutant of concern discharged by an individual point source in that category.[15] Here, 40 C.F.R. Part 423 provides effluent limitations for certain pollutants discharged by the steam electric power generating point source category, but not for heat.[16] Therefore, EPA may use BPJ to set BAT limits for thermal discharges from individual

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[13] CWA § 402(a)(1), 33 U.S.C. 1342(a)(1).

[14] See, e.g., American Mining Congress v. EPA, 965 F.2d 759, 762 n.3 (9th Cir. 1992) ("When EPA has not yet issued national effluent guidelines for a category of point sources, the Agency is authorized under CWA § 402(a)(1), 33 U.S.C. § 1342(a)(1), to develop such limitations in an NPDES permit on a case-by-case basis.") (challenge to stormwater discharge rule), *citing* NRDC v. Costle, 568 F.2d 1369, 1378-79 (D.C. Cir. 1977); NRDC v. EPA, 859 F.2d at 195 (BPJ limits are "technology-based limitations set, in the absence of a national guideline, according to a permit writer's best professional judgment, pursuant to § 402(a)(2) of the CWA"); NRDC v. EPA, 822 F.2d 104, 111 (D.C. Cir. 1987) ("If no national standards have been promulgated for a particular category of point sources, the permit writer is authorized to use, on a case-by-case basis, 'best professional judgment' to impose 'such conditions as the permit writer determines are necessary to carry out the provisions of [the Clean Water Act.]") (citations omitted) (related case regarding industry and environmental group challenge to 1979 revisions to NPDES regulations); American Petroleum Inst., 787 F.2d at 969 ("Where EPA has not promulgated applicable technology-based effluent limitations guidelines, the permits must incorporate, on a case-by-case method, 'such conditions as the Administrator determines are necessary to carry out the provisions of the Act.'") (citations omitted).

[15] 40 C.F.R. § 125.3(c)(3); Manual at p. 69.

[16] See Note 1 and accompanying text.

facilities in the steam electric power generating category, which includes BPS.[17]

4.2.3 Best Available Technology Economically Achievable-Based Limits

For toxic pollutants and for non-conventional pollutants such as heat, the CWA requires the achievement of

> effluent limitations for categories and classes of point sources, other than publicly owned treatment works, which ... shall require application of the best available technology economically achievable for such category or class, which will result in reasonable further progress toward the national goal of eliminating the discharge of all pollutants, as determined in accordance with regulations issued by the [EPA] Administrator pursuant to [CWA § 304(b)(2),] section 1314(b)(2) of this title, which such effluent limitations shall require the elimination of discharges of all pollutants if the Administrator finds, on the basis of information available to him ... that such elimination is technologically and economically achievable for a category or class of point sources as determined in accordance with regulations issued by the [EPA] Administrator pursuant to [CWA § 304(b)(2),] section 1314(b)(2) of this title ....[18]

That is, EPA must set limits that represent a minimum level of treatment based on technologies that are technologically available and economically achievable, and that will result in reasonable progress toward the elimination of the discharge of such pollutants.[19]

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[17] See In the Matter of Public Service Co. of New Hampshire (Seabrook Station, Units 1 and 2), NPDES Appeal No. 76-7, 1977 WL 22370, *6 (E.P.A.), 1 E.A.D. 332 (1977); In Re Central Hudson Gas & Electric Corp., Decision of General Counsel No. 63, EPA (Jul. 29, 1977), at 376; Status of Initial Decision of Regional Administration Where Appeal is Pending, General Counsel Opinion, EPA (Jan. 11, 1977), EPA GCO 77-1, at 1.

[18] CWA § 301(b)(2), 33 U.S.C. § 1311(b)(2) (emphasis added).

[19] See CWA §§ 301(b)(2)(A), 304(b)(2)(B), 33 U.S.C. §§ 1311(b)(2)(A), 1314(b)(2)(B). See also BP Exploration & Oil, Inc. v. EPA, 66 F.3d 784, 790 (6th Cir. 1995) (“Compared to BPT, BAT calls for more stringent control technology that is both technologically available and economically achievable.”); Rybachek v. EPA, 904 F.2d 1276, 1290 (9th Cir. 1990) (“By definition, BAT limitations must be both technologically available and economically achievable.”) (industry challenge to EPA regulations implementing BAT limits for placer mining point sources); NRDC v. EPA, 863 F.2d at 1426 (“Technology-based limitations under BAT must be both technologically available and economically achievable.”).

The CWA requires EPA to "take into account" the following factors when setting BAT limits for a particular point source category or individual discharger:

> the age of the equipment and facilities involved, the process employed, the engineering aspects of the application of various types of control techniques, process changes, the cost of achieving such effluent reduction, non-water quality environmental impact (including energy requirements), and such other factors as the Administrator deems appropriate.[20]

The statute sets up a loose framework for assessing these factors in setting BAT limits.[21] It does not require their comparison, merely their consideration.[22] Moreover, "[i]n enacting the CWA, 'Congress did not mandate any particular structure or weight for the many consideration factors. Rather, it left EPA with discretion to decide how to account for the consideration factors, and how much weight to give each factor.'"[23] In sum, when EPA considers the BAT factors in setting BAT limits, it is governed by a standard of reasonableness.[24] It must consider each factor, but it has "considerable discretion in evaluating the relevant factors and determining the weight to be

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[20] CWA § 304(b)(2)(B), 33 U.S.C. § 1314(b)(2)(B). See also 40 C.F.R. § 125.3(d)(3).

[21] BP Exploration & Oil, Inc., 66 F.3d at 796, *citing* Weyerhauser v. Costle, 590 F.2d 1011, 1045 (D.C. Cir. 1978) (citing Senator Muskie's remarks on CWA § 304(b)(1) factors during debate on CWA). See also EPA v. Nat'l Crushed Stone Ass'n, 449 U.S. 64, 74, 101 S.Ct. 295, 300, 66 L.Ed.2d 268 (1980) (noting with regard to BPT that "[s]imilar directions are given the Administrator for determining effluent reductions attainable from the BAT except that in assessing BAT total cost is no longer to be considered in comparison to effluent reduction benefits") (industry challenge to EPA regulations implementing BAT limits for point sources in coal mining industry and certain portions of mineral mining and processing industry).

[22] Weyerhauser v. Costle, 590 F.2d at 1045 (explaining that CWA § 304(b)(2) lists factors for EPA "consideration" in setting BAT limits, while CWA § 304(b)(1) lists both factors for EPA consideration and factors for EPA "comparison" -- "total cost versus effluent reduction benefits" -- in setting BPT limits).

[23] BP Exploration & Oil, Inc., 66 F.3d at 796, *citing* Weyerhauser v. Costle, 590 F.2d at 1045.

[24] Id., 66 F.3d at 796, *citing* American Iron & Steel Inst. v. EPA, 526 F.2d 1027, 1051 (1975), *modified in other part*, 560 F.2d 589 (3d Cir. 1977), *cert. denied*, 435 U.S. 914, 98 S.Ct. 1467, 55 L.Ed.2d 505 (1978) (industry challenge to EPA regulations implementing BAT limits for iron and steel industry point sources).

accorded to each in reaching its ultimate BAT determination."[25] One court has succinctly summarized the standard for measuring EPA's consideration of the BAT factors in setting BAT limits: "[s]o long as the required technology reduces the discharge of pollutants, our inquiry will be limited to whether the Agency considered the cost of technology, along with other statutory factors, and whether its conclusion is reasonable."[26]

When imposing BAT limits using BPJ under § 402(a)(1), a permit writer is required to apply both the statutory BAT factors and the factors specified in 40 C.F.R. § 125.3(d)(3), and to consider both the "appropriate technology for the category of point sources of which the applicant is a member, based on all available information," and "any unique factors relating to the applicant."[27] The 40 C.F.R. § 125.3(d)(3) factors are the age of the equipment and facilities involved, the process employed, the engineering aspects of the application of various types of control techniques, process change, the cost of achieving such effluent reduction, and non-water quality

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[25] Texas Oil & Gas Ass'n, 161 F.3d at 928, *citing* NRDC v. EPA, 863 F.2d at 1426. See also Weyerhauser, 590 F.2d at 1045 (discussing EPA's discretion in assessing BAT factors, court noted that "[s]o long as EPA pays some attention to the congressionally specified factors, the section [304(b)(2)] on its face lets EPA relate the various factors as it deems necessary").

Historically, certain factors, such as age, process employed and non-water quality impacts, have assumed lesser importance than the technical and economic feasibility evaluations. Manual at 71.

[26] Ass'n of Pacific Fisheries v. EPA, 615 F.2d 794, 818 (9th Cir. 1980) (industry challenge to EPA regulations implementing BAT limits for seafood processing industry point sources). See also Chemical Manufacturers Ass'n (CMA) v. EPA, 870 F.2d 177, 250 n.320 (5th Cir. 1989), *citing* Congressional Research Service, A Legislative History of the Water Pollution Control Act Amendments of 1972 at 170 (1973) (hereinafter "1972 Legislative History") (in determining BAT, "'[t]he Administrator will be bound by a test of reasonableness.'") (industry challenge to EPA regulations implementing BAT limits for organic chemicals, plastics and synthetic fibers industry point sources); NRDC v. EPA, 863 F.2d at 1426 (same); American Iron & Steel Inst., 526 F.2d at 1051 (same).

[27] 40 C.F.R. § 125.3(c)(2). See also NRDC v. EPA, 863 F.2d at 1425 ("in issuing permits on a case-by-case basis using its 'Best Professional Judgment,' EPA does not have unlimited discretion in establishing permit limitations. EPA's own regulations implementing [CWA § 402(a)(1)] enumerate the statutory factors that must be considered in writing permits.").

The Manual states that BPJ "means the highest quality technical opinion that the permit writer can develop after considering all reasonably available and pertinent data or information forming the basis for the terms and conditions of a NPDES permit." Manual at p. 68.

environmental impact (including energy requirements).[28] These are the same exact factors used to establish nationwide BAT limits (i.e., BAT ELGs) under CWA §§ 301(b)(2) and 304(b)(2). Moreover, as noted above, the permit writer using BPJ to develop BAT limits applies the same performance-based approach to each individual point source that EPA applies to categories and classes of point sources when it develops ELGs.[29]

4.2.3a Technological Availability

According to the CWA's legislative history, "best available" technology refers to the "single best performing plant in an industrial field."[30] Thus, EPA may set BAT limits that are not

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[28] 40 C.F.R. § 125.3.(d)(3). Compare CWA § 304(b), 33 U.S.C. §1314(b).

[29] E.g., Texas Oil & Gas Ass'n, 161 F.3d at 929 (under 40 C.F.R. § 125.3, "EPA must determine on a case-by-case basis what effluent limitations represent the BAT level, using its 'best professional judgment.' Individual judgments thus take the place of uniform national guidelines, but the technology-based standard remains the same.") (citation omitted); NRDC v. EPA, 859 F.2d at 201('in establishing BPJ limits, EPA considers the same statutory factors used to establish national effluent guidelines. BPJ limits thus represent the level of technology control mandated by the CWA for the particular point source."); Trustees for Alaska v. EPA, 749 F.2d 549, 553 (9th Cir. 1984) (EPA must consider statutorily enumerated factors in its BPJ determination of effluent limits); Manual at p. 70. See also NRDC v. EPA, 863 F.2d at 1425 ("courts reviewing permits issued on a BPJ basis hold EPA to the same factors that must be considered in establishing the national effluent limitations") (citations omitted).

[30] CMA v. EPA, 870 F.2d at 239, *citing* 1972 Legislative History at 170. See also Texas Oil & Gas Ass'n, 161 F.3d at 928, *quoting* CMA v. EPA, 870 F.2d at 226; Kennecott v. EPA, 780 F.2d 445, 448 (4th Cir. 1985) (industry challenge to EPA regulations implementing BAT limits for nonferrous metals manufacturing industry point sources) ("In setting BAT, EPA uses not the average plant, but the optimally operating plant, the pilot plant which acts as a beacon to show what is possible."); American Meat Inst. v. EPA, 526 F.2d 442, 463 (7th Cir. 1975)(industry challenge to EPA regulations implementing BAT limits for meat products industry point sources) (BAT "should, at a minimum, be established with reference to the best performer in any industrial category"). According to one court,

> [t]he legislative history of the 1983 regulations indicates that regulations establishing BEA [i.e., best available technology economically achievable, or BAT] can be based on statistics from a single plant. The House Report states:
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> > It will be sufficient for the purposes of setting the level of control under available technology, that there be one operating facility

technologically achievable by all of the dischargers in a particular point source category, as long as one discharger in the category demonstrates that the limits are achievable.[31] This comports with Congress's intention that EPA "use the latest scientific research and technology in setting effluent limits, pushing industries toward the goal of zero discharge as quickly as possible."[32]

EPA has determined that "available" technologies include any viable "transfer technologies" (that is, technology from another industry that could be transferred to the industry in question), as well as technologies that have been shown to be viable in research even if not yet implemented at a full-scale facility.[33] When EPA bases BAT limits on such "model" technologies, it is not required to "consider the temporal availability of the model technology to individual plants," because the BAT factors do not include consideration of an individual plant's lead time for obtaining and

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> which demonstrates that the level can be achieved or that there is sufficient information and data from a relevant pilot plant or semi-works plant to provide the needed economic and technical justification for such new source.

Ass'n of Pacific Fisheries, 615 F.2d at 816-17, *quoting* 1972 Legislative History at 170.

31 CMA v. EPA, 870 F.2d at 239, 240.

32 Kennecott, 780 F.2d at 448, *citing* 1972 Legislative History at 798. See also NRDC v. EPA, 863 F.2d at 1431 ("The BAT standard must establish effluent limitations that utilize the latest technology").

33 These determinations, arising out of the CWA's legislative history, have been upheld by the courts. E.g., American Petroleum Inst. v. EPA, 858 F.2d 261, 264-65 (5th Cir. 1988) (challenge to two general permits containing BPJ-based BAT and BAT-level limits for offshore oil and gas drilling industry point sources discharging to Alaskan Outer Continental Shelf); Ass'n of Pacific Fisheries, 615 F.2d at 816-17; BASF Wyandotte Corp. v. Costle, 614 F.2d 21, 22 (1st Cir. 1980) (industry challenge to EPA regulations implementing BAT limits for organic pesticide industry point sources); American Iron and Steel Inst., 526 F.2d at 1061; American Meat Inst., 526 F.2d at 462.

See also Kennecott v. EPA, 780 F.2d at 453, *citing* Reynolds Metals v. EPA, 760 F.2d 549, 562 (4th Cir. 1985) ("Congress contemplated that EPA might use technology from other industries to establish the Best Available Technology."). The Kennecott court provides the test for determining whether a technology from one industry may be applied to another industry. See 780 F.2d at 453, *citing* Tanners' Council of America, Inc. v. Train, 540 F.2d 1188, 1192 (4th Cir. 1976).

installing the technology.[34]

EPA must articulate the reasons for its determination that the technology it has identified as BAT is technologically achievable. Courts have construed the CWA as not requiring EPA to identify the specific technology or technologies a plant must install to meet BAT limits.[35] The Agency must nonetheless demonstrate that the technology used to estimate BAT limit costs is a "reasonable approximation of the type and cost of technology that must be used to meet the limitations."[36] It may do this by several methods, including relying on a study that demonstrates the effectiveness of the required technology.[37]

Age of Equipment and Facilities Involved. Among the BAT factors that EPA must consider in developing BAT limits are the age of the equipment and facility or facilities involved. Age by itself is not relevant to the type of treatment technology to be installed to achieve BAT limits. The type of treatment technology to be applied is primarily a function of the pollutants present in a facility's effluent and thus is a function of the type of operation conducted, not the facility's age. However, age does have a bearing on the cost and feasibility of retrofitting existing plants to meet BAT limits.[38] As one court explained,

> [w]hile all the plants in a certain older subcategory ... may require the same technological processes to reduce effluent discharges, the fact that all the plants within that subcategory were built long before plants in another subcategory may present special problems in installing anti-pollution devices. Similarly, in a

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34 See CMA v. EPA, 870 F.2d at 243; American Meat Inst., 526 F.2d at 451.

35 See CMA v. EPA, 870 F.2d at 241.

36 CMA v. EPA, 870 F.2d at 241.

37 BP Exploration & Oil, Inc., 66 F.3d at 794 (where petitioners challenged technological achievability of BAT limits for produced water discharged by offshore oil and gas extraction facilities on grounds that technology that EPA identified as BAT, improved gas flotation, removes only dispersed oil from produced water, court upheld BAT limits because EPA relied on "empirical data" presented in studies demonstrating that improved gas flotation is effective technique for removing dissolved as well as dispersed oil from produced water). Compare Ass'n of Pacific Fisheries, 615 F.2d at 819 (in challenge to EPA regulations implementing BAT limits for seafood processing industry point sources, regulations remanded because EPA based BAT limit on study that failed to demonstrate effectiveness of technology identified as BAT).

38 See American Iron & Steel Inst., 526 F.2d at 1048.

> subcategory where there is considerable variation in age, the fact that processes are similar may mean that the same type of control technology can be installed, but it does not necessarily mean that the ease with which that technology can be installed, or the ability to comply with effluent limitations once it has been installed, is not affected by age.[39]

In that case, the court remanded EPA regulations implementing BAT limits for iron and steel point sources on the grounds that the Agency had failed to consider the BAT factor of age as it affected the cost and feasibility of retrofitting certain older steel mills to meet the BAT limits.[40]

When considering the age factor under CWA §§ 301(b)(2) and 304(b)(2) and 40 C.F.R. § 125.3(d)(3), EPA may proceed on the basis of "'imperfect' information ... unless 'there is simply no rational relationship' between the means used to account for any imperfections and the situation to which those means are applied."[41] For example, the Agency properly designated reinjection as BAT for produced water generated by coastal oil and gas drilling facilities even though it had excluded pre-1980 oil and gas wells from its CWA § 308 survey of known coastal operators, on which it relied heavily in its economic impact analysis, because its extrapolation of data from the survey to estimate the economic impacts on pre-1980 facilities was reasonable. More particularly, to support this extrapolation of data, EPA determined that the only relevant distinction between pre-1980 and post-1980 wells was that pre-1980 wells were primarily "marginal producers" (i.e., they produced ten barrels a day or less), pre-1980 marginal producers did not differ significantly from post-1980 marginal producers, and post-1980 marginal producers were well-represented in the survey.[42]

In sum, to set a BPJ-based BAT limit for thermal discharges from BPS in accordance with CWA §§ 301(b)(2) and 304(b)(2) and 40 C.F.R. § 125.3(d)(3), EPA considered the age of the electric power generation units comprising the facility and their cooling system components as it had a bearing on both the costs of retrofitting one or more those units with the available treatment technologies that the Agency was evaluating as BAT, and the feasibility of such retrofitting.

Process Employed/Engineering Aspects of the Application of Various Types of Control Techniques/Process Changes. The factors that EPA must consider in developing BAT limits

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[39] Id.

[40] Id.

[41] Texas Oil & Gas Ass'n, 161 F.3d at 935. This holds true for all of the BAT factors. Id.

[42] Id.

also include the process or processes employed by the point source category or subcategory or the individual discharger for which the BAT limits are being developed; engineering aspects of the treatment technologies that are being evaluated as BAT; and the changes to the point source process or processes that will result from application of the treatment technology in question.

As noted above, EPA has "considerable discretion in evaluating the relevant factors and determining the weight to be accorded to each in reaching its ultimate BAT determination."[43] For example, the Agency can determine that the use of a particular technology is feasible and will achieve a level of effluent reduction, but that the technology cannot be designated as BAT in part because its use will result in a significant loss in production.[44]

In setting the BPJ-based BAT limit for thermal discharges from BPS, EPA considered the steam electric power generation processes currently employed by BPS; engineering concerns relating to the application of the treatment technologies evaluated as BAT to these processes; and the types of process changes that would result. These factors are related to the age factor discussed above insofar as they relate to the feasibility of retrofitting the existing facility to achieve BAT.

4.2.3b Economic Achievability

CWA §§ 301(b)(2) and 304(b)(2) require "EPA to set discharge limits that reflect the amount of pollutant that would be discharged by a point source employing the best available technology that the EPA determines to be economically feasible ...."[45] The United States Supreme Court has read these sections to mean that BAT should "represent 'a commitment of the maximum

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[43] Id. at 928, *citing* NRDC v. EPA, 863 F.2d at 1426. See also Kennecott v. EPA, 780 F.2d at 448, *citing* CWA § 304(b)(2), 33.U.S.C. § 1314(b)(2).

[44] BP Exploration & Oil, Inc. v. EPA, 66 F.3d at 796 (in establishing BAT limits for produced waters discharged by offshore oil and gas extraction facilities, EPA did not improperly weigh BAT factors in determining that while reinjection may be technologically feasible, "loss of production resulting from reinjection," in combination with high cost and adverse environmental impacts, was valid basis for rejecting reinjection as BAT).

[45] Texas Oil & Gas Ass'n, 161 F.3d at 928. See also CWA § 301(b)(2), 33 U.S.C. § 1311(b)(2) (BAT limits "shall require the elimination of discharges of all pollutants if the Administrator finds, on the basis of information available to him ... that such elimination is ... economically achievable"); CWA § 304(b)(2), 33 U.S.C. § 1314(b)(2) (when assessing BAT for particular point source category or individual discharger, EPA must take "cost of achieving such effluent reduction" into account); 40 C.F.R. § 125.3(d)(3) (same).

resources economically possible to the ultimate goal of eliminating all polluting discharges."[46]

The Act gives EPA "considerable discretion" in determining what is economically achievable.[47] It does not require a precise calculation of the costs of complying with BAT limits.[48] Rather, EPA "need make only a reasonable cost estimate in setting BAT," meaning that it must "develop no more than a rough idea of the costs the industry would incur."[49] Moreover, CWA § 301(b)(2) does not specify any special method of evaluating the costs of compliance with BAT limits or state how those costs should be considered in relation to the other BAT factors. It only directs EPA to consider whether the costs associated with pollutant reduction are "economically

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[46] Nat'l Crushed Stone Ass'n, 449 U.S. 64, 74, 101 S.Ct. at 302, 66 L.Ed.2d 268. See also BP Exploration & Oil, Inc., 66 F.3d at 790 ("BAT represents, at a minimum, the best economically achievable performance in the industrial category or subcategory."), *citing* NRDC, 863 F.2d at 1426 (citing Nat'l Crushed Stone Ass'n).

[47] NRDC v. EPA, 863 F.2d at 1426, *citing* American Iron & Steel Inst., 526 F.2d at 1052.

[48] BP Exploration & Oil, Inc., 66 F.3d at 803. This court stated that

> [a]ccording to EPA, the CWA not only gives the agency broad discretion in determining BAT, the Act merely requires the agency to consider whether the cost of the technology is reasonable. EPA is correct that the CWA does not require a precise calculation of BAT costs.

Id., *citing* NRDC v. EPA, 863 F.2d at 1426.

[49] NRDC v. EPA, 863 F.2d at 1426. See also Rybachek, 904 F.2d at 1290-91 (citing NRDC v. EPA); CMA v. EPA, 870 F.2d at 237-38 (same).

Among the costs EPA may consider are the costs of BAT compliance and their economic impact. This may include estimating plant production and capacity and computing probable revenues, and then comparing compliance costs to revenues; or calculating changes in cost of production, increase in price and changes in return on investment, and then comparing compliance investment costs to average capital expenditures. E.g., Kennecott, 780 F.2d at 456-57. It also may include estimating the costs of construction, labor, power, chemicals and fuel needed to build and operate a new treatment system. E.g., Ass'n of Pacific Fisheries, 615 F.2d at 818. Where appropriate, EPA may analyze the cost of acquiring and clearing land required to build treatment systems, but it is not required to do so when developing ELGs, in part because these costs can be considered site-specific. E.g., CMA v. EPA, 870 F.2d at 241-242; Ass'n of Pacific Fisheries, 615 F.2d at 818, 819-20; American Iron & Steel Inst., 526 F.2d at 1053.

achievable."[50] Similarly, CWA § 304(b)(2)(B) only requires EPA to "take into account" the costs of BAT along with the other BAT factors.[51]

Courts including the United States Supreme Court have consistently read the statute and its legislative history as indicating Congress's intention that while EPA should consider costs in setting BAT limits, it is not required to perform a cost-benefit analysis or any other type of balancing test.[52] More than one court has pointed to the 1972 House-Senate conference report for the Act, which states that

> [w]hile cost should be a factor in the Administrator's judgment, no balancing test

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[50] CMA v. EPA, 870 F.2d at 250, *citing* CWA § 301(b)(2)(A), 33 U.S.C. § 1311(b)(2)(A).

[51] See CWA § 304(b)(2)(B), 33 U.S.C. § 1314(b)(2)(B). See also Reynolds Metals Co., 760 F.2d at 565 (in setting BAT limits, "no balancing is required -- only that costs be considered along with the other factors discussed previously"), *citing* Nat'l Ass'n Metal Finishers v. EPA, 719 F.2d 624, 662-63 (3rd Cir. 1983); Ass'n of Pacific Fisheries, 615 F.2d at 818 (in setting BAT limits, "the EPA must 'take into account ... the cost of achieving such effluent reduction,' along with various other factors. Section 304(b)(2)(B).").

Stated differently, rather than invalidate effluent limitations on the basis of cost alone, courts should look to determine whether EPA has properly weighed all of the BAT factors in setting BAT limits for a particular point source category or point source. See CMA v. EPA, 870 F.2d at 252 ("In light of Congress' judgment that society must bear such costs as the price of achieving the long-term benefits of eliminating pollutants from our nation's waters, courts have been exceedingly reluctant to invalidate environmental regulations on grounds of cost ...."). See also BP Exploration & Oil, Inc., 66 F.3d at 796 (in establishing BAT limits for produced waters discharged by offshore oil and gas extraction facilities, EPA did not improperly weigh BAT factors in determining that reinjection may be technologically feasible, but "extraordinary cost" of implementation, in combination with resulting loss of production and adverse environmental impacts, was valid basis for rejecting reinjection as BAT).

[52] E.g., Nat'l Crushed Stone Ass'n, 449 U.S. 64, 101 S.Ct. at 300, 66 L.Ed.2d 268 ("Similar directions [to those for assessing BPT under CWA § 304(b)(1)(B)] are given the Administrator for determining effluent reductions attainable from the BAT except that in assessing BAT total cost is no longer to be considered in comparison to effluent reduction benefits.") (footnote omitted); Texas Oil & Gas Ass'n , 161 F.3d at 936 n.9 (petitioners asked court "to reverse years of precedent and to hold that the clear language of the CWA (specifically, 33 U.S.C. § 1314(b)(2)(B)) requires the EPA to perform a cost-benefit analysis in determining BAT. We find nothing in the language or history of the CWA that compels such a result").

> will be required. The Administrator will be bound by a test of reasonableness. In this case, the reasonableness of what is 'economically achievable' should reflect an evaluation of what needs to be done to move toward the elimination of the discharge of pollutants and what is achievable through the application of available technology – without regard to cost.[53]

One federal appeals court has nonetheless held that in setting BAT limits, EPA must compare the cost of a particular technology to the non-monetary environmental benefits of using that technology to determine whether the technology's cost is "reasonable." In remanding the ELGs that EPA had promulgated for the steam electric power generating point source category in 1974, the Fourth Circuit in Appalachian Power Co. rejected the petitioners' contention that under CWA §§ 301(b)(2) or 304(b)(2), "benefits derived from a particular level of effluent reduction must be quantified in monetary terms." It found, however, that

> [n]evertheless, EPA is under a statutory duty to determine whether, in fact, its regulations for 1983 will 'result in reasonable further progress toward the national goal of eliminating the discharge of all pollutants ....' 33 U.S.C. s 1311(b)(2)(A). Accordingly, the agency must consider the benefits derived from the application of its effluent reduction requirements in relation to the associated costs in order to determine whether, in fact, the resulting progress is 'economically achievable,' and whether the progress is 'reasonable.'[54]

Subsequently, two other federal appeals courts – the Fifth and the Ninth Circuits – have referred to Appalachian Power Co. for support in dicta questioning the reach of the "reasonableness" test

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[53] E.g., Ass'n of Pacific Fisheries, 615 F.2d at 817, *quoting* 1972 Leg. Hist. at 170; CMA v. EPA, 870 F.2d at 250 n.320 (same); NRDC v. EPA, 863 F.2d at 1426 (same); American Iron & Steel Inst., 526 F.2d at 1051-52 (same).

In addition, more than one court has compared EPA's assessment of cost in setting BAT limits with its assessment of cost in setting BPT limits, and concluded that while setting BPT limits involves a limited comparison of technology costs and effluent reduction benefits, setting BAT limits involves even less. E.g., American Iron & Steel Institute, 526 F.2d at 1051. As the American Iron & Steel Institute court explained, "for 'BATEA' [i.e., BAT] standards, cost was to be less important than for the 'BPCTCA' [i.e., BPT] standards, and that for even the 'BPCTCA' standards, cost was not to be given primary importance." 526 F.2d at 1052 n.51.

[54] Appalachian Power Co., 545 F.2d at 1361, *citing* CWA § 301(b)(2)(A), 33 U.S.C. § 1311(b)(2)(A).

that guides EPA's consideration of cost in setting BAT limits.[55] However, these courts affirmed EPA's use of the test, explicitly holding that the Agency is not required to undertake any cost-benefit analysis or otherwise balance a technology's environmental benefits against its associated costs when setting BAT limits.[56]

Overall, the vast majority of courts have held that the CWA bars a direct comparison of the costs and benefits of pollutant reduction in the BAT limit-setting process.[57] As one court concisely

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[55] Ass'n of Pacific Fisheries, 615 F.2d at 818 ("at some point extremely costly more refined treatment will have a de minimis effect on the receiving waters"); American Petroleum Inst., 787 F.2d at 972 ("Indeed, EPA would disserve its mandate were it to tilt at windmills by imposing BAT limitations which removed de minimis amounts of polluting agents from our nation's waters, while imposing possibly disabling costs upon the regulated industry.").

[56] See Ass'n of Pacific Fisheries, 615 F.2d at 817 (citing 1972 House-Senate conference report language regarding "test of reasonableness," court held that "EPA must consider the economic consequences of the 1983 regulations, along with the other factors mentioned in section 304(b)(2)(B)," but that "the language of the statute indicates that the EPA's consideration of costs in determining BPT and BEA [i.e., BAT] was to be different," and that "[t]he conspicuous absence [in CWA § 304(b)(2)(B)] of the comparative language contained in section 304(b)(1)(B) leads us to the conclusion that Congress did not intend the Agency or this court to engage in marginal cost-benefit comparisons") (citations omitted); American Petroleum Inst., 787 F.2d at 972 ("Unlike §§ 304(b)(1) and 304(b)(4), which define the criteria for BPT and BCT, respectively, § 304(b)(2) does not expressly direct that the Administrator compare costs with effluent reduction benefits in determining BAT limitations.") (footnote omitted).

In other words, Congress has directed that courts may not invalidate BAT limits on the basis of cost alone, but rather must determine whether EPA has properly weighed all the BAT factors in setting the limits in question. The courts have generally followed Congress's direction. See CMA v. EPA, 870 F.2d at 252 ("In light of Congress' judgment that society must bear such costs as the price of achieving the long-term benefits of eliminating pollutants from our nation's waters, courts have been exceedingly reluctant to invalidate environmental regulations on grounds of cost ....").

[57] E.g., Nat'l Crushed Stone Ass'n, 449 U.S. 64, 101 S.Ct. at 300 n.10, 66 L.Ed.2d 268 (unlike CWA § 301(b)(1)(B), which governs BPT standards, CWA § 304(b)(2)(B) "does not state that costs shall be considered in relation to effluent reduction"); Texas Oil & Gas Ass'n , 161 F.3d at 936 ("In applying the BAT standard, the EPA is not obligated to evaluate the reasonableness of the relationship between costs and benefits."); Rybachek, 904 F.2d at 1290-91 ("In determining the economic achievability of a technology, the EPA must consider the 'cost' of meeting BAT limitations, but need not compare such cost with the benefits of effluent

stated,

> [t]he benefit to be achieved from adopting a particular pollution control technology is not an element of that technology's cost. The cost of complying with a BAT-based regulation can be gauged by reference to the cost of the technology itself, even if the benefits of using that technology are unclear.[58]

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reduction.") (citing Nat'l Crushed Stone Ass'n and Ass'n of Pacific Fisheries); CMA v. EPA, 870 F.2d at 250 ("[b]oth Congress and the Supreme Court have made clear that in setting BAT, the EPA is not required to compare the costs against the benefits of pollution reduction in the same manner as the EPA is required to do in setting BPT standards.") (citing Nat'l Crushed Stone Ass'n); Reynolds Metals Co., 760 F.2d at 565 ("For BPT there must be a 'limited balancing' of costs against benefits, but as regards BAT ... no balancing is required – only that costs be considered along with those factors discussed previously."); Ass'n of Pacific Fisheries, 615 F.2d at 818 (with regard to CWA § 304(b)(2)(B), "Congress did not intend the Agency or this court to engage in marginal cost-benefit comparisons"); American Petroleum Inst., 787 F.2d at 972 ("§ 304(b)(2) does not expressly direct that the Administrator compare costs with effluent reduction benefits in determining BAT limitations"); American Iron & Steel Inst., 526 F.2d at 1051 ("With respect to the 1983 'BATEA' [i.e., BAT] standards, Senator Muskie intended that the type of assessment should be basically the same [as the BPT standards], except that there should be no cost-benefit analysis."); American Meat Inst., 526 F.2d at 462-63 ("No formal cost-benefit analysis is required in determining the 'best available' technology, although the Administrator is to take cost into consideration.").

[58] Texas Oil & Gas Ass'n, 161 F.3d at 936. In rejecting the petitioners' challenges to a study that EPA had used to estimate the "pollution reduction benefits" that would result from use of a particular technology as BAT, the Texas Oil & Gas Ass'n court held that "[w]hatever value such benefit estimates may have, they are not a required part of the BAT determination. In applying the BAT standard, the EPA is not obligated to evaluate the reasonableness of the relationship between costs and benefits." Id., *citing* Nat'l Crushed Stone Ass'n, 449 U.S. 64, 101 S.Ct. at 300, 66 L.Ed.2d 268.

See also American Petroleum Inst., 858 F.2d at 265 n.5 (where petitioners claimed that BAT limits would have "'infinitesimal' impact at a 'monumental' cost," court held that "BAT limitations properly may require industry, regardless of a discharge's effect on water quality, to employ defined levels of technology to meet effluent limitations; a direct cost-benefit correlation is not required, so even minimal environmental impact can be regulated, so long as the prescribed alternative is 'technologically and economically achievable") (citing 4 Leg. History of the Clean Water Act of 1977: A Continuation of the Leg. History of the Fed. Water Pollution Control Act, 95th Cong., 2d Sess. 1469-70 (1978)); BP Exploration & Oil, Inc., 66 F.3d at 800

In sum, the CWA provides that "even minimal environmental impact can be regulated" as long as the BAT limits in question are 'technologically and economically achievable."[59] When a court reviews EPA's BAT determination for a specific point source category or individual discharger, "[s]o long as the required technology reduces the discharge of pollutants, [the court's] inquiry will be limited to whether the Agency considered the cost of technology, along with other statutory factors, and whether its conclusion is reasonable.'"[60] EPA's obligation is to meet its "duty to explain its cost analysis fully."[61]

Therefore, in setting the BPJ-based BAT limit for thermal discharges from BPS, EPA considered the costs of particular technologies that could be used as BAT at the plant, the economic impact of these costs on the permittee and ratepayers, and the reasonableness of these costs and impacts in light of the CWA's ultimate goal of eliminating the discharge of all pollutants.

4.2.3c Non-Water Quality Environmental Impacts

EPA is not required to consider water quality impacts in setting BAT limits.[62] It is, however, required under CWA § 304(b)(2) and 40 C.F.R. § 125.3(d)(3) to consider environmental impacts that are not water quality-related. In fact, EPA may determine that a particular technology is technologically available and economically achievable but should not be the basis for BAT limits because of unacceptably high non-water quality environmental impacts.[63]

(where industry petitioners claimed that BAT limits for offshore oil and gas extraction point sources discharging within three miles of shore were improperly promulgated because "environmental benefits" of limits were "negligible," court affirmed EPA's position that in setting BAT limits, Agency "need only find that the technology is technologically and economically achievable and that the cost of the technology is reasonable").

[59] American Petroleum Inst., 858 F.2d at 265.

[60] Ass'n of Pacific Fisheries, 615 F.2d at 818.

[61] Kennecott, 780 F.2d at 456, *citing* Ass'n of Pacific Fisheries, 615 F.2d at 820.

[62] See, e.g., American Petroleum Inst., 858 F.2d at 265-266 ("Because the basic requirement for BAT effluent limitations is only that they be technologically and economically achievable, the impact of a particular discharge upon the receiving water is not an issue to be considered in setting technology-based limitations.").

[63] See, e.g., BP Exploration & Oil, Inc., 66 F.3d at 796 (in establishing BAT limits for produced waters discharged by offshore oil and gas extraction facilities, EPA properly weighed BAT factors in determining that while reinjection was technologically feasible, combination of

The CWA gives EPA broad discretion in deciding how to evaluate non-water quality environmental impacts and weigh them against the other BAT factors.[64] EPA does not need, for example, to demonstrate that the non-water quality environmental impacts of a particular technology are "'wholly disproportionate' to the possible pollution reduction" that would result from applying the technology to set BAT limits.[65] Rather, the Agency must apply its discretion and expertise to the relevant information at hand regarding the "relative impact of two different environmental harms," and demonstrate on the record that it has considered this information in light of all the BAT factors.[66]

"negative impact reinjection would have on air emissions," high cost, and resulting loss of production was valid basis for rejecting it as BAT); id. at 800 (while zero discharge of drilling fluids and cuttings was technologically available and economically achievable for all offshore drilling platforms in Gulf of Mexico, including drilling platforms beyond three miles from shore, lack of landfill capacity in region was "unacceptably high nonwater quality environmental impact[]" and thus proper basis for establishing three-mile zero discharge limit); id. at 801 (while zero discharge was technologically available and economically achievable for all offshore drilling platforms in California, including drilling platforms beyond three miles from shore, zero discharge option's "serious impact on air pollution" was, in EPA's view, "unacceptably high nonwater quality environmental impact[]" and thus proper basis for establishing three-mile zero discharge limit). See also Weyerhauser, 590 F.2d at 1045 (discussing EPA's discretion in assessing BAT factors, court noted that "[s]o long as EPA pays some attention to the congressionally specified factors, the section [304(b)(2)] on its face lets EPA relate the various factors as it deems necessary").

[64] Rybachek, 904 F.2d at 1297 (discussing evaluation of nonwater quality environmental impacts under CWA § 304 in context of challenge to EPA regulations establishing BAT limits for placer mining industry point sources), *citing* Weyerhauser, 590 F.2d at 1049-53 (discussing evaluation of nonwater quality environmental impacts under CWA § 304 in context of challenge to EPA regulations establishing BPT limits for pulp and paper industry point sources).

[65] See BP Exploration & Oil, Inc., 66 F.3d at 801 (EPA was within its discretion in deciding that increased air emissions that would result from barging all drilling wastes from offshore oil and gas extraction platforms to coast of California "vastly outweighed" benefit of imposing zero discharge limitation to platforms beyond three miles from shore).

[66] See, e.g., BP Exploration & Oil, Inc., 66 F.3d at 800 (record supported EPA's determination that zero discharge is BAT for drilling wastes discharged by offshore oil and gas extraction facilities within three miles of shore in Gulf of Mexico by showing that EPA not only properly estimated both projected volume of waste from certain drilling platforms and availability of landfill capacity, but also "continuously reevaluated data and collected comments"and

4.2.3d Other Factors EPA Deems Appropriate

i. EPA's Use of Data

In establishing BAT limits, EPA has broad discretion in its selection of data and in its methods of calculation.[67] Its conclusions with respect to data and analysis "need only fall within a 'zone of reasonableness.'"[68]

For example, where the Agency relies on scientific data from several sources, one of those sources may be a data set that is not complete without several years of data, which are unavailable.[69] In addition, EPA may "borrow" data where direct data is not available, as long as its assumptions are logical and there is nothing in the record to establish that they led to scientifically inaccurate results.[70] For example, where for a particular pollutant it does not have sufficient plant variability data to calculate a variability factor that reflects the observed variations in treatment performance experienced by plants attempting to remove that pollutant from their discharge, EPA may use the average of those variability factors that it has established for pollutants exhibiting similar chemical structure and characteristics, or the average of the

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"revis[ed] its information" to keep it up to date); Rybachek, 904 F.2d at 1297 (record demonstrates that EPA determined that placer mining industry compliance with BAT requirements would require certain specified number of gallons of fuel per year, and further demonstrates how EPA reached determination and considered it in establishing BAT requirements); American Iron & Steel Inst., 526 F.2d at 1049 (record demonstrates that in setting BAT limits for iron and steel industry point sources, EPA "considered both the problems of air pollution and solid waste disposal, as well as the problem of additional energy requirements caused by installation of the necessary anti-pollution devices"). See also Weyerhauser, 590 F.2d at 1045 (discussing EPA's discretion in assessing BAT factors, court noted that "[s]o long as EPA pays some attention to the congressionally specified factors, the section [304(b)(2)] on its face lets EPA relate the various factors as it deems necessary").

[67] E.g., BP Exploration & Oil, Inc., 66 F.3d at 804; Reynolds Metals Co., 760 F.2d at 565.

[68] Reynolds Metals Co., 760 F.2d at 559, *quoting* Hercules, Inc. v. EPA, 598 F.2d 91, 107 (D.C.Cir. 1978).

[69] See BP Exploration & Oil, Inc., 66 F.3d at 804, *citing* Reynolds Metals Co., 760 F.2d at 565, *and* American Petroleum Inst. v. EPA, 540 F.2d 1023, 1035-36 (10th Cir. 1976), *cert. denied*, 430 U.S. 922, 97 S.Ct. 1340, 51 L.Ed.2d 601 (1977).

[70] CMA v. EPA, 870 F.2d at 228, *citing* BASF Wyandotte, 598 F.2d at 656.

variability factors for all the other pollutants that it found to be treatable by the same technology.[71]

EPA similarly has discretion in its choice of statistical methods.[72] For example, in establishing BAT limits, it may average over a long term the amount of a pollutant discharged by the best plant or plants in a point source category using BAT technology, and then use weighted averaging - multiplying the long-term average by a variability factor greater than one - to account for the variation from that average that could be expected by the best plant or plants.[73]

4.3 The Technological Availability of Cooling System Options for Reducing Thermal Discharges from BPS

4.3.1 Background

As stated above, the goal of this section is to establish thermal load limitations based on BAT for BPS in accordance with CWA §§ 301(b)(2) and 304(b)(2) and 40 C.F.R. § 125.3(d)(3). The section first considers a range of potential technological options for reducing thermal discharges from the plant. Several of these potential options are screened out based on factors that EPA believes indicate they would not be preferred over the alternatives that are retained for detailed evaluation of whether they are BAT for reducing thermal discharges from BPS. The section then presents these detailed evaluations, which consider technological, economic, non-water quality-related environmental and energy-related aspects of each of the preferred options. Finally, the section presents EPA's conclusions regarding the degree to which each preferred option meets the Act's requirements that it be both technologically available and economically achievable and result in "reasonable further progress toward the national goal of eliminating the discharge of all pollutants."[74] Based on these conclusions, EPA presents the BAT limit for the discharge of heat from BPS.

Because BPS is an existing plant, EPA must evaluate what constitutes BAT for reducing thermal discharges from the plant keeping in mind that the technology or combination of technologies on which BPS's BPJ-based BAT limit would be based would be a retrofit. EPA recognizes that BPS may have less flexibility in designing and locating cooling water system components, and may incur higher compliance costs, than a new plant. EPA also recognizes that retrofitting

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[71] Id.

[72] E.g., id., 870 F.2d at 228; BASF Wyandotte, 598 F.2d at 655.

[73] CMA v. EPA, 870 F.2d at 227-28.

[74] CWA § 301(b)(2), 33 U.S.C. § 1311(b)(2).

technologies at BPS may require brief shutdown periods during which the plant would lose both production and revenues, and that certain retrofits could decrease the plant's thermal efficiency. Finally, EPA recognizes that BPS may have certain site limitations, such as a lack of undeveloped space, that may make certain technologies infeasible.[75]

Nonetheless, it should be clearly understood that technologies exist that generate electricity with little or no discharge of heated cooling water. Indeed, these technologies, including wet cooling towers and dry cooling towers, have been in widespread use for many years and generally result in few or no adverse environmental impacts. None of these technologies is automatically considered BAT under the current case-by-case approach to reducing thermal discharges from new or existing steam electric power plants. Rather, each technology's availability and economic achievability must be addressed on a site-specific basis. As explained above, for BPS, this involves consideration of (1) each technology's availability for use at BPS; (2) the technology's costs, including the economic impact of these costs on the permittee and ratepayers, and the reasonableness of these costs and impacts in light of the CWA's goal of eliminating all pollutant discharges; and (3) the technology's performance in terms of non-water quality-related environmental and energy impacts and other impacts that EPA deems appropriate.

In evaluating technology alternatives for reducing the thermal load discharged from BPS into Mount Hope Bay, EPA has considered both the material submitted by the permittee and other materials, such as EPA's own expert engineering analyses, relevant guidance documents, information regarding experience at other power plants, and information from equipment manufacturers.

As part of its permit application, and in response to EPA information requests, the permittee has submitted a significant amount of information related to potential thermal load (and flow) reduction technologies. Since issuance of the current NPDES permit in 1993, the permittee has submitted several major documents to the permitting agencies addressing technologies to support the next permit reissuance. The permittee has also made several smaller submissions and a number of presentations at meetings on this topic.

In late 1996, EPA sent the New England Power Company (NEPCO), then the permittee and owner and operator of BPS, an information request letter under CWA § 308. This request sought, among other things, information related to alternative technologies that might be used at BPS to reduce the effects of the plant's thermal discharge to Mount Hope Bay and the adverse environmental impacts from both the entrainment and impingement of marine life by its cooling water intake structures (CWISs). NEPCO contracted Stone and Webster Engineering Company (Stone & Webster) to describe and compare alternatives. NEPCO then submitted to EPA a Stone

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[75] See 65 Fed. Reg. 49064 (August 10, 2000).

& Webster report entitled "Feasibility Study of Cooling Water System Alternatives for Brayton Point Generating Station" (January, 1997) (the "January 1997 NEPCO Report").

In September, 1998, NEPCO sold BPS to USGenNE, which continued the Section 316(b) alternative technology analyses. On February 22, 2001, USGenNE submitted a report entitled, "NPDES Renewal: USGen New England, Inc., Brayton Point Station, Somerset, Massachusetts" to EPA New England and MA DEP. This report attached a February 2001 report entitled "Summary of Cooling System Alternatives Analysis for Reducing Thermal Discharge and Entrainment and Impingement at Brayton Point Station." It stated that it summarized and condensed certain new information on "Cooling System Alternatives" provided by Stone & Webster, but also indicated that Stone & Webster was still doing additional work for USGenNE. Subsequently, USGenNE submitted the May 24, 2001 Partial 316(a) and (b) Demonstration. On September 10, 2001, in response to another EPA information request letter, USGenNE submitted a document entitled "A Response to Section 308 Information Request dated August 10, 2001." The latter document also evaluates certain technological alternatives for reducing BPS's thermal discharges and the volume of water withdrawn through its CWISs.

Then, on December 7, 2001, the permittee made a new submission to EPA and MA DEP entitled "Clean Water Act Section 316(a) and (b) Demonstration, Brayton Point Station Permit Renewal Application" (November 2001) (hereinafter, the "December 2001 USGenNE 316(a) and (b) Demonstration"). This submission includes five large volumes with thousands of pages of material, including a 67-page "Executive Summary." Certain portions of this material had been submitted previously by the permittee, while other portions had not. Such a late submission of this voluminous, complex package by the permittee – the permittee's application for permit renewal was due, and was originally filed by the permittee, in January 1998 – created a challenge for the regulatory agencies, but the agencies have endeavored to carefully review and consider the material in the December 2001 USGenNE 316(a) and (b) Demonstration.

A significant point must be made regarding the above-mentioned submissions by the permittee: that in preparing these materials, the permittee imposed certain conceptual limitations on its analyses of cooling water system technologies that may be used for thermal load reduction at BPS. For example, the January 1997 NEPCO Report considered only thermal load reduction alternatives that reduce the average monthly thermal loading by a maximum of approximately $2x10^{12}$ (trillion) BTUs.[76] EPA was not aware of these limitations on the permittee's analysis prior

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[76] The baseline heat load to Mount Hope Bay from BPS currently peaks around $4x10^{12}$ [trillion] BTUs per month. <u>See</u> "Clean Water Act Section 316(a) and (b) Demonstration, Brayton Point Station Permit Renewal Application" (November 2001) (hereinafter "December 2001 USGenNE 316(a) and (b) Demonstration"), Vol. III, App. G, Tab: USGenNE § 308 Response of September 10, 2001, Table B-2.

to receiving the January 1997 NEPCO Report, and it neither approved them nor otherwise indicated that an evaluation of thermal load reduction technologies based on such limitations would suffice under the CWA.

Similarly, the permittee's February 2001 submittal states that "[t]he focus of the ongoing cooling system alternatives analysis is to identify alternatives and combinations of alterations that could (a) reduce the station's thermal discharge to levels that existed before Unit 4 started discharging heat into Mt. Hope Bay and (b) reduces circulation water flows to levels equivalent to Units 1, 2 and 3 only."[77] In a June 19, 2001 letter, EPA explained to the permittee that EPA and the States have not adopted these plant performance criteria for their own evaluations of what constitutes adequate performance, and that they would instead look to the criteria provided in federal and state environmental laws. The letter also noted that EPA and the States had explained to the permittee at several meetings that they had not determined whether rolling back the plant's thermal discharge and cooling water intake profile to the levels observed before Unit 4 was converted to once-through cooling would be sufficient to meet the environmental standards of applicable laws.[78] Nevertheless, the permittee continued to use this criterion for judging alternatives in the December 2001 USGenNE 316(a) and (b) Demonstration.[79]

Finally, the permittee's analysis of thermal load reduction alternatives in App. H of the December 2001 USGenNE 316(a) and (b) Demonstration is similarly limited. In that report, the permittee judged technological alternatives by whether or not they could "(a) reduce the station's thermal discharge to levels below MOA II and below levels that existed before Unit 4 started discharging heat into Mt. Hope Bay and (b) reduce circulating water flows to levels below MOA II and below historical flows associated with Units 1, 2, and 3 only."[80] The BAT analysis presented in this determination document is not limited by this constraint, i.e., EPA has not evaluated only those alternatives that could reduce BPS's thermal discharge to pre-Unit 4 levels.

4.3.2 Cooling System Options for Reducing Thermal Discharges from Steam Electric Power Generating Plants

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77 "Summary of Cooling System Alternatives Analysis for Reducing Thermal Discharge and Entrainment and Impingement at Brayton Point Station" (February 2001) (attached to "NPDES Renewal: USGen New England, Inc., Brayton Point Station, Somerset, Massachusetts" dated February 22, 2001), p. 7.

78 See June 19, 2001 letter from David Webster, EPA, to Meredith Simas, PG&E/NEG.

79 See December 2001 USGenNE 316(a) and (b) Demonstration, Vol. IV, § 4.4.

80 Id., Vol. IV, App. H, at 1-6.

Generally, steam electric powerplants employ one of four basic types of circulating water cooling systems to reject waste heat. These systems are (1) "once-through" or open-cycle cooling (which is presently used at BPS), (2) once-through cooling with supplemental cooling on the discharge, (3) recirculating or "closed-cycle" cooling, and (4) a combination of these three systems. A once-through system discharges the entire amount of cooling water, and thus the entire amount of the waste heat discharged by the plant, to the receiving water body. A once-through system with supplemental cooling (e.g., from "helper" cooling towers) removes a portion of the waste heat from the plant effluent before discharge to the receiving water and transfers this energy to the atmosphere. A closed-cycle or recirculating system employs a cooling device that withdraws the plant's waste energy from the cooling water and releases it directly to the atmosphere, thus enabling the plant to recirculate and reuse the cooling water.

There is another type of cooling system that does not use cooling water. This type of system employs "dry cooling" towers, which use a natural or a mechanical air draft to transfer heat from condenser tubes to the atmosphere without the evaporative loss of water. There are two types of dry cooling systems for power plant applications: direct dry cooling and indirect dry cooling. Direct dry cooling systems utilize air to directly condense steam, while indirect dry cooling systems utilize a closed cycle water cooling system to condense steam, and the heated water is then air cooled.[81] Dry cooling tower (or air-cooled condenser) systems are regarded to be substantially more expensive than wet cooling tower systems.[82]

Also worthy of note is the "hybrid" (or "wet/dry") system, which combines principles of wet and dry cooling tower operations.[83] For the most common type of hybrid system, exhaust steam

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[81] Technical Development Document for the Final Regulations Addressing Cooling Water Intake Structures for New Facilities (EPA-821-R-01-036) (November 2001) (hereinafter "EPA TDD 2001 - New Facilities"), Chapter 4, p. 1. See also 66 Fed. Reg. 65282 (Dec. 18, 2001); EPA Office of Water, "Economic and Engineering Analysis of the Proposed § 316(b) New Facility Rule) (August 2000), App. A, p. 14 (hereinafter "EPA Economic and Engineering Analysis").

[82] See, e.g., 66 Fed. Reg. 65282-83 (Dec. 18, 2001).

[83] Wet/dry cooling towers combine dry heat exchange surfaces with standard wet cooling towers. This technology would be less expensive than dry cooling but more expensive than a wet cooling tower system. See 65 Fed. Reg. 49081 (August 10, 2000) (discussion of wet/dry towers); Science Applications International Corporation (SAIC), "Review of USGen New England Brayton Point Station Section 316 Demonstration Report" (March 15, 2002) (hereinafter "SAIC Report (March 15, 2002)"), Table 5. The permittee did not evaluate the retrofitting or use of wet/dry cooling towers at BPS. EPA will not establish BAT limits for BPS based on the wet/dry cooling tower technology, but the permittee may use this technology to

flows through smooth tubes, where it is condensed by a mixture of cascading water and air. The water and air move in a downward direction across the tube bundles and the air is forced upward for discharge to the atmosphere. The falling water is collected and recirculated, similarly to a wet cooling tower.[84] This technology typically has greater capital costs than basic wet cooling towers but can eliminate costs attributable to outages or mitigation related to water vapor plumes from wet mechanical draft cooling towers.[85] In addition, a plant may use generation curtailment, which involves curtailing electricity generation to a level that would enable the plant to reduce the amount of cooling water it discharges.

There is no question that as a general matter, wet, dry and wet/dry cooling towers are technologically available for use at power plants. Wet cooling towers have been widely used at power plants for many years.[86] Air cooling is also a viable technology. In fact, air cooling systems have recently been proposed for installation for new units at the Mystic and Fore River Stations in Massachusetts.[87] In addition, a number of plants use wet/dry cooling towers.[88]

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meet the final permit requirements if it chooses.

[84] EPA TDD 2001 - New Facilities, Chapter 4, p. 1.

[85] See 65 Fed. Reg. 49081 (August 10, 2000) (discussion of wet/dry tower); December 10, 2001 telephone memorandum from Sharon Zaya, EPA, regarding call with Gary Mirsky, P.E. Hamon Cooling Towers, N.J.; January 4, 2002 telephone memorandum from Sharon Zaya, EPA, regarding call with Ken Daledda, Bergen Station, New Jersey; 39 Fed. Reg. 36192 (October 8, 1974); EPA Economic and Engineering Analysis, App. A, p. 14; SAIC Report (March 15, 2002), Table 5.

[86] See, e.g., 65 Fed. Reg. 49080-81 (August 10, 2000); 1996 EPA Supplement to Background Paper No. 3, p. A-3; 41 Fed. Reg. 17388 (April 26, 1976); 1976 Draft EPA CWA § 316(b) Guidance, p. 13; EPA 1976 Development Document (April 1976), pp. 149-57, 191; 39 Fed. Reg. 36192 (October 8, 1974).

[87] See 65 Fed. Reg. 49080-81 (August 10, 2000); November 6, 2000 Letter from Vern Lang (US F&WS) to EPA Proposed Rule Comment Clerk, p. 3 (comments on EPA's proposed regulations under CWA § 316(b) for new power plants listing number of plants currently operating, under construction, or recently approved for air (or "dry") cooling); EPA Economic and Engineering Analysis, App. A, p. 14.

[88] See, e.g., 65 Fed. Reg. 49080-81 (August 10, 2000); EPA Economic and Engineering Analysis, App. A, pp. 14-15; 39 Fed. Reg. 36192 (October 8, 1974); Literature from Marley Cooling Tower Company; Public Service Commission of Wisconsin/Wisconsin Department of Natural Resources, Final Environmental Impact Statement, Badger Generating

Nonetheless, to establish BPJ-based BAT limitations on thermal discharges from BPS in accordance with CWA §§ 301(b)2) and 304(b)(2), EPA must determine which of these closed-cycle cooling technologies, if any, is available for *retrofitting* specifically *at BPS*.[89]

Moreover, as discussed above, EPA must consider other factors, including non-water quality environmental and energy-related impacts, in determining whether the thermal discharge reductions achievable from one of these technologies is BAT for BPS under the CWA. For example, cooling towers can be tall, though not necessarily as tall as other power plant facilities, such as air emission stacks. As a result, EPA must consider not only logistical issues, such as available space for installing the towers, but also potential visual impacts. For wet cooling tower systems, EPA must consider whether there are any concerns related to the emission of mist or water vapor that may travel from the plant onto nearby receptors. For wet mechanical draft and dry cooling tower systems, EPA must consider potential noise impacts from the fans used in the cooling process. In addition, the use of a closed-cycle cooling technology can result in a marginal loss of plant efficiency and lead to increased energy usage and air emissions. EPA must consider all of these factors in evaluating the costs of each technology alternative and the environmental significance of potential increased fuel consumption and air pollution.

It is important to note that a power plant can combine the use of closed-cycle and open-cycle cooling technologies to reduce overall thermal discharges to a predetermined level or to prevent going above a specified cost threshold.[90] Such "combination options" could make particular sense at existing plants being considered for retrofit technology changes, because it could be easier and less expensive for an existing plant to retrofit to partially closed-cycle cooling instead of completely closed-cycle cooling. Indeed, the permittee's "Enhanced Multi-Mode" proposal,

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Company, LLC, Electric Generation and Transmission Facilities (June 2000, 9340-CE-100), Executive Summary.

89 It is nonetheless noteworthy that between 1955 and 1997, the number of new steam electric power plants using closed-cycle cooling water systems increased from 25 percent to 75 percent, with a corresponding decrease in plants using once-through systems. Between 1975 and 1984, the number of steam electric power plants using closed-cycle recirculating systems increased 31 percent. This trend toward the use of closed-cycle recirculating systems is projected to continue as new plants are built. Of the seven new generating plants that would potentially be covered by the recently proposed CWA § 316(b) rule and for which EPA has planning information, all seven plan to use closed-cycle recirculating cooling water systems. See 65 Fed. Reg. 49072 and n.5 (August 10, 2000). EPA estimates that 84 percent of existing steam electric generating plants started operation between 1955 and 1985. An additional 7 percent of these plants started operation between 1985 and 1997. Id.

90 See 1994 EPA Background Paper No. 3, p. 2-3.

which is discussed below, is a sort of combination option. Accordingly, EPA has considered alternatives for BPS that involve partially shifting the plant to closed-cycle cooling while also allowing some open-cycle cooling to remain.

4.3.2a Closed-Cycle Cooling/Cooling Tower Options

There are two basic methods of heat rejection through a closed-cycle cooling system. The first uses cooling ponds or lakes. These typically consist of artificially constructed bodies of water built by damming a natural watershed. The condenser water is fed into the cooling pond or lake, cooled through evaporation and then recycled to the condenser.[91] The permittee did not evaluate the retrofitting or use of cooling ponds or lakes at BPS. EPA will not establish BAT limits for BPS based on the technological alternative of cooling ponds/cooling lakes, but the permittee may use this alternative to meet the final permit requirements if it chooses.

The second basic closed-cycle cooling method is wet (or evaporative) cooling using wet cooling towers.[92] In systems that employ conventional wet cooling towers, water that has been used to cool the condensers is pumped to the top of a cooling tower; as the heated water falls, it cools through an evaporative process, and the tower emits warm, moist air.[93] More specifically, wet cooling towers reduce the temperature of the water by bringing it directly into contact with large amounts of air. Through this process, heat is transferred from the water to the air, which is then discharged into the atmosphere. Part of the water evaporates through this process, thereby having a cooling effect on the rest of the water. This water then exits the cooling tower at a temperature approaching the wet bulb temperature of the air.[94]

i. Mechanical Draft versus Natural Draft Wet Cooling Towers

There are two principal types of wet cooling towers used in closed-cycle systems: natural draft towers and mechanical draft towers. Natural draft towers have no mechanical device to create air

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[91] Cooling ponds and lakes are similar in principle to open, once-through systems but are closed inasmuch as no significant thermal discharge occurs beyond the confines of the pond or lake. Appalachian Power Co., 545 F.2d at 1358, 1368 and n.44.

[92] See 1994 EPA Background Paper No. 3, pp. 2-3 to 2-5 (general discussion of cooling towers); 66 Fed. Reg. 65282 (Dec. 18, 2001).

[93] See 65 Fed. Reg. 49081 (August 10, 2000).

[94] EPA Economic and Engineering Analysis, App. A, p. 14.

flow through the tower and are usually applied in very small or very large applications.[95] They induce natural air flow by the chimney effect produced by the height and shape of the tower. Mechanical draft towers use fans in the cooling process.[96] They reject waste heat by the evaporation of a small percentage of the heated discharge water inside cells that are supplied with air flows induced by large fans.[97] For towers of similar capacity, natural draft towers typically require significantly less land area and have lower power costs, because fans to induce air flow are not needed; however, they also typically have higher initial costs, particularly because they need to be taller than mechanical draft towers.

The permittee evaluated the use of both natural draft and mechanical draft cooling towers for thermal load and flow reduction at BPS and concluded that natural draft cooling towers should be dropped from consideration. The reason for this decision was the permittee's determination that although the two technologies offer equivalent reductions in heat rejection (and in flow), natural draft towers are significantly more expensive to construct and pose more serious adverse visual impacts because they are much taller.[98]

EPA concurs with the permittee's decision to drop natural draft cooling towers from further consideration, and focuses on mechanical draft cooling tower-based alternatives in its evaluation of BAT alternatives for reducing the thermal load from BPS. Although EPA has not performed a detailed review of the costs predicted by the permittee for natural draft towers, our research indicates that the relative costs that the permittee has predicted for the two types of towers are approximately accurate, i.e., that natural draft towers are likely to cost significantly more than mechanical draft towers while achieving the same level of thermal discharge reductions.[99] In addition, the visual/aesthetic impacts are more severe for natural draft towers because of their great height (approximately six times as high on average as mechanical draft towers).[100]

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[95] See 1994 EPA Background Paper No. 3, p. 2-4.

[96] See id., p. 2-4; EPA Economic and Engineering Analysis, p. 11-2 to 11-3; App. A, p. 14.

[97] December 2001 USGenNE 316(a) and (b) Demonstration, Vol. IV, App. H, p. 3-1.

[98] February 22, 2001 Letter from Meredith M. Simas, PG&E/NEG, to David Webster, EPA, and Edward P. Kunce, MA DEP, Attachment 1, p. 4. See also December 2001 USGenNE 316(a) and (b) Demonstration, Vol. IV, App. H, at 1-3; January 1997 NEPCO Report, Table 6-1.

[99] See EPA Economic and Engineering Analysis, App. A, p. 14.

[100] See January 1997 NEPCO Report, pp. 3-13, 3-19.

EPA notes that mechanical draft towers are likely to be somewhat noisier and more costly to operate than natural draft towers, because of the fans and the energy needed to run them.[101] The Agency has determined, however, that these issues are not so significant as to enjoin the use of mechanical draft towers. EPA believes that any noise effects from the operation of mechanical draft towers can be sufficiently mitigated/controlled to meet applicable noise standards.[102] (Noise is discussed further below.) Moreover, the Agency believes that the difference in the energy use and operation and maintenance costs between the two technologies is not large enough to be a significant issue and would be offset by the increased capital costs for the natural draft towers. (Energy and cost issues at BPS are discussed further below.)

It should also be noted that although natural draft towers may emit less mist or water vapor than mechanical draft towers, this advantage is likely to be more than offset by the fact that any plumes will travel farther from the taller natural draft towers than they would from the shorter mechanical draft towers.[103] While it may not be entirely clear which technology would be preferable from this perspective, even if natural draft towers had a marginal advantage, EPA still agrees with the permittee's decision to focus on mechanical draft towers for the following reasons: we do not believe the plume problems to be particularly significant, and we believe that there are means to address any such problems, and that at this site the advantages of mechanical draft towers (i.e., lower cost, fewer visual/aesthetic impacts) outweigh any marginal advantage that natural draft towers might have in this regard. Mechanical draft towers are a widely used technology at power plants in the United States and abroad, clearly indicating that their impacts are generally not unacceptable.

ii. **General Applicability of Mechanical Draft Cooling Towers at BPS**

As a general matter, mechanical draft cooling towers appear to be technologically available for retrofitting at BPS. Such cooling towers have been designed and installed to work effectively in

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101 See January 1997 NEPCO Report, pp. 3-15, 3-21, 3-22; EPA Economic and Engineering Analysis, App. A, p. 14.

102 See EPA Economic and Engineering Analysis, App. A, p. 14.

103 Compare 39 Fed. Reg. 36189, 36192 (Oct. 8, 1974) with EPA TDD 2001 - New Facilities, p. 3-33; January 9, 2002 e-mail from Timothy Connor, EPA Headquarters, to Mark Stein, EPA Region 1; December 12, 2001 memorandum from Mark Stein to Brayton Point NPDES Permit File ("Brief Notes on an Issue Discussed During Conference Call with John Gulvas of Consumers Energy and the Palisades Nuclear power station in Covert, Michigan"); January 1997 NEPCO Report, p. 3-15.

cooling systems using salt or brackish water, as BPS's existing cooling system does.[104] Moreover, experience at other plants has shown that closed-cycle mechanical draft cooling towers can be retrofitted to an existing once-through power plant.[105] Indeed, the permittee has not argued that such a retrofit would be unfeasible.[106]

The permittee has submitted information regarding its views of the engineering requirements and capital and operating costs that would be involved in retrofitting closed-cycle cooling at BPS. It has also submitted information indicating that retrofitting all or some of the units at BPS with closed-cycle mechanical draft cooling towers could cause adverse noise, visual/aesthetic, fogging and icing impacts and likely would result in a marginal decrease in electricity generated for sale by the plant due to an "efficiency penalty" and an "auxiliary power penalty": a decrease that would represent a cost to the permittee. Moreover, according to the permittee, shifting to closed-cycle cooling *potentially* could lead to marginal increases in air pollution if the plant were to burn more fuel in an effort to generate more electricity to offset the lost electrical generation. EPA agrees that retrofitting cooling towers for all or some of the generating units at BPS would be a complicated construction project involving significant costs. Nonetheless, the Agency does not believe based on current information that any of these issues presents a clear fatal flaw with regard to the installation of mechanical draft cooling towers as a retrofit at BPS.

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[104] See, e.g., December 2001 USGenNE 316(a) and (b) Demonstration, Vol. IV, App. H, p. 3-2 ("[s]ince the 1970s, a large number of successful, reliable salt water cooling towers have been installed," mostly in southern and western United States); Technical Development Document for the Proposed Section 316(b) Phase II Existing Facilities Rule (EPA 821-R-02-003) (April 2002) (hereinafter "EPA TDD 2002 - Existing Facilities"), p. 4-1; December 20, 2001 e-mail from Timothy Connor, EPA Headquarters, to Mark Stein, EPA Region 1.

[105] See SAIC Report (March 15, 2002), Attachment A (Case 4); Memorandum from Nick Prodany and Mark Stein to Brayton Point NPDES Permit File, "Notes on Telephone Call with Engineer at Canadys Station power plant in South Carolina;" December 12, 2001 memorandum from Mark Stein to Brayton Point NPDES Permit File ("Brief Notes on an Issue Discussed During Conference Call with John Gulvas of Consumers Energy and the Palisades Nuclear power station in Covert, Michigan"); January 1997 NEPCO Report, p. 3-6; December 18, 2001 e-mail from Timothy Connor, EPA Headquarters, to Mark Stein, EPA Region 1.

[106] EPA acknowledges that the permittee has pointed to a number of detriments for retrofitting closed-cycle mechanical draft cooling towers at BPS, and has reached the opinion that retrofitting *the entire facility* to closed-cycle cooling towers would be "unsuitable" for a variety of economic, engineering and environmental reasons. See December 2001 USGenNE 316(a) and (b) Demonstration, Vol. I, Executive Summary, p. 8, n.7. The company has, however, proposed the installation of its "Enhanced Multi-Mode" system, which utilizes a 20-cell mechanical draft wet cooling tower.

Therefore, EPA evaluates below whether closed-cycle cooling for the entire BPS plant, i.e., retrofitting a mechanical draft cooling tower at each of the plant's four generating units, would be BAT for controlling thermal discharges from BPS. The conclusions of this detailed evaluation, including an independent analysis of the costs and whether those costs are reasonable, are presented below. EPA also evaluates alternatives for partial closed-cycle cooling at BPS using mechanical draft cooling towers: shifting Unit 3 only to closed-cycle cooling, or shifting Units 1 or 2 and Unit 3 to closed-cycle cooling. These alternatives are the subject for detailed BAT evaluation because each could achieve major incremental reductions in thermal loading short of that which would be achieved by installing mechanical draft cooling towers for the entire plant. EPA's conclusions regarding these partial closed-cycle cooling alternatives are also presented below.

The Agency notes that these three closed-cycle alternatives use wet cooling towers that are engineered to work only with specific generating units. The permittee has indicated that if such a unit-specific cooling tower needed to be shut down (e.g., due to a safety hazard from any water vapor plume), then the associated generating unit would also have to be shut down.[107] EPA has learned through its own research, however, that a number of power plants around the United States have wet cooling towers that are used part of the time (e.g., to accommodate seasonal environmental concerns about once-through cooling operations) and by-passed at other times, allowing the facility to operate in once-through mode.[108] Therefore, in the detailed BAT analysis below, EPA considers this "by-pass" concept as a variation on the Closed-Cycle Unit 3 and Closed-Cycle Entire Station options.

EPA also evaluates another alternative that takes advantage of mechanical draft cooling tower technology. The permittee has proposed this alternative, which it calls "Enhanced Multi-Mode."[109] EPA believes the permittee has demonstrated technological ingenuity in developing

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107 See December 2001 USGenNE 316(a) and (b) Demonstration, Vol. IV, App. H, p. 3-4.

108 See February 8, 2002 telephone memorandum by Sharon Zaya, EPA ("Phone Call to Drew Seidel, Plant Manager at Victoria Power Station, TX"); February 8, 2002 telephone memorandum by Sharon Zaya, EPA ("Phone Call to Tom Shusko, Plant Manager at Albright Power Station, WV"); January 24, 2002 memorandum from Mark Stein, EPA, to Brayton Point NPDES Permit File ("Notes on Telephone Conversation with Gary Kolle of Prairie Island Nuclear Generating Station in Minnesota"); January 23, 2002 e-mail from Timothy Connor, EPA Headquarters, to Mark Stein, EPA; January 11, 2002 e-mail from Michael Moe, SAIC, to Mark Stein, EPA;

109 See generally PG&E/NEG § 308 Response of September 10, 2001; December 2001 USGenNE 316(a) and (b) Demonstration, Vol. IV, App. H.

the Enhanced Multi-Mode proposal, and that the proposal warrants detailed evaluation by EPA.

As conceived by the permittee, the Enhanced Multi-Mode system would use mechanical draft cooling towers that could operate in either closed-cycle, helper or piggyback mode to maximize thermal discharge reductions while giving the power plant greater operational flexibility and minimizing costs. Through a major reconfiguration of the piping components within the plant, each of these multi-mode cooling towers would not manage heated effluent solely from a specific, associated generating unit. Rather, each tower would draw heated effluent from the discharge canal, cool it, and recycle the cooled water back to individual units. As a result, these towers would be able to provide thermal discharge and cooling water flow reductions even if particular generating units are not in operation, by cooling the hot water from those units that are in operation. A unit-specific cooling tower would provide no such benefit when its associated generating unit is not operating. In other words, beyond the thermal discharge and flow reductions that would occur when a particular generating unit is off-line, the Enhanced Multi-Mode system would provide an additional benefit because it could be used to address the heat from other units that *are* operating, i.e., as helper towers.[110]

Another key aspect of the permittee's Enhanced Multi-Mode proposal is that it would enable cooling towers to be bypassed, and generating units to remain in production, if necessary to abate water vapor plumes (as discussed in detail below).[111] In the permittee's view, the system would avoid plume abatement outages related to roadway icing and reduce potentially costly construction-related outages. Finally, the Enhanced Multi-Mode alternative is the permittee's preferred option.[112]

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[110] See December 2001 USGenNE 316(a) and (b) Demonstration, Vol. IV, App. H, p. 3.1-1 and Tables 3.1-1 and 3.1-2.

[111] See id., p. 3.1-10.

[112] See id., Vol. I, Executive Summary, p. 1.

The permittee also proposed a "Basic Multi-Mode" cooling system alternative. See id., Vol. IV, App. H, § 3.1.2. EPA believes that it is not necessary to evaluate this alternative to determine whether it may be BAT for reducing thermal discharges from BPS, because the Enhanced Multi-Mode alternative achieves greater thermal discharge reductions at a similar cost. More particularly, the Enhanced Multi-Mode alternative would "achieve further flow and heat reduction compared to the basic multi-mode system by utilizing additional piping ... at a cost of approximately $9 million." It would "allow[] both Units 3 and 4 to operate in a closed-cycle mode" and "would also be capable of cooling the discharge of Units 1 and 2 in a helper cooling tower mode." Id., p. 3.1-15. With the Basic Multi-Mode option, only Unit 4 would be capable of operating in a closed-cycle mode. Compare id., Table 3.1-1, with id., Table 3.1-2.

The technological alternatives discussed above utilize mechanical draft cooling towers in full closed-cycle, partial closed-cycle and "multi-mode" cooling systems. Taken together, they represent a reasonable and appropriate range of alternatives for significantly reducing thermal discharges from BPS.

4.3.2b Non-Closed-Cycle Cooling/Cooling Tower Options

i. Dry Cooling Towers

The use of air or dry cooling towers would yield the maximum reduction in thermal loading to Mount Hope Bay from BPS by essentially eliminating the use of water for cooling. In dry cooling towers, the water does not come in direct contact with the air but instead travels in closed pipes through the tower. Air going through the tower flows along the outside of the pipe walls and absorbs heat from the pipe walls, which absorb heat from the water in the pipes.

In general, dry cooling towers tend to be much larger and more costly than wet towers since the dry cooling process is less efficient.[113] Also, the effluent water temperature is warmer since it only approaches the dry bulb temperature of the air (not the cooler wet bulb temperature).[114] Nonetheless, dry cooling towers have several advantages over wet cooling towers. They do not

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[113] See EPA Economic and Engineering Analysis, App. A, p. 14; 66 Fed. Reg. 65282-84, 65304-06 (Dec. 18, 2001) (various estimates put costs of dry cooling as from 1.75 to three times more than cost of wet cooling); January 1997 NEPCO Report, Table 6-1 (preliminary capital cost estimate of $63.4 for dry cooling for Unit 4 versus $27.8 for mechanical draft wet cooling for Unit 4). See also SAIC Report (March 15, 2002), Table 5 (costs for hybrid wet/dry cooling towers approximately 2.5 times that of plain wet towers).

The costs in the January 1997 NEPCO Report only address options that provide closed-cycle cooling only for Unit 4. It should also be noted that the more detailed cost analyses conducted by the permittee for the December 2001 USGenNE 316(a) and (b) Demonstration have resulted in substantially higher cost estimates. Compare January 1997 NEPCO Report, Table 6-1 (capital costs for mechanical draft cooling tower for Unit 4 estimated at $27.8 million), with December 2001 USGenNE 316(a) and (b) Demonstration, Vol. IV, App. H, p. 3.3-18 (capital costs for mechanical draft cooling tower for Unit 4 estimated at $48 million). Thus, it is fair to assume the permittee's estimates for dry cooling would also increase substantially, though the permittee provided no cost estimate for converting any or all of the BPS units to dry cooling in its December 2001 USGenNE 316(a) and (b) Demonstration.

[114] See EPA TDD 2001 - New Facilities, § 4.2.2; EPA Economic and Engineering Analysis, App. A, p. 14.

consume water through evaporation, they have no wastewater discharge to affect water quality, they do not cause the drift of salt or other minerals, they do not require the use and subsequent treatment of water conditioning chemicals or biocides, and they do not create a vapor plume. Moreover, because plants employing dry cooling systems have no cooling water needs, they can be located near or in cities and other areas with great demand for electricity irrespective of the availability of large supplies of cooling water, thereby reducing costs and power losses associated with transmitting electricity over long distances.[115]

The permittee looked at a dry cooling alternative for Unit 4 only in the January 1997 NEPCO Report but did not carry this alternative forward for further detailed analysis.[116] According to the report, the dry cooling alternative would be "marginally feasible" but was a poor alternative due to its greater cost (more than twice as expensive), greater size (potentially posing space constraints), greater noise and greater diminishment of plant power generation capacity.[117] The report also noted that because a retrofit from once-through to dry cooling had never been completed, to the permittee's knowledge, it would be inherently difficult and require especially complicated and expensive engineering and design work.[118] In the December 2001 USGenNE 316(a) and (b) Demonstration, the permittee stated that dry cooling "was determined to be infeasible because this technology has never been retrofitted to an existing station and thus has significant risk of operating failure."[119]

EPA does not agree that retrofitting some or all the generating units at BPS to dry cooling has been demonstrated to be "infeasible." While the Agency is not aware of any examples of plants that have switched from once-through cooling to dry cooling, such a conversion is not necessarily infeasible just because it may not have been completed in the past. Indeed, the January 1997 NEPCO Report stated that dry cooling was "marginally feasible" for Unit 4.

EPA nonetheless shares the permittee's view that the absence of a track record of such conversions must be cause for serious caution and concern, and that this caution must grow as

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115 65 Fed. Reg. 49081 (August 10, 2000).

116 See January 1997 NEPCO Report, pp. 3-6 to 3-9; December 2001 USGenNE 316(a) and (b) Demonstration, Vol. IV, App. H, p. 1-3.

117 See January 1997 NEPCO Report, pp. 3-8 to 3-9.

118 Id., p. 3-8.

119 December 2001 USGenNE 316(a) and (b) Demonstration, Vol. IV, App. H, p. 1-3. This does not appear to be a fully accurate representation of the January 1997 NEPCO report's conclusions.

more units are considered for conversion. As a result, like the permittee, EPA has also decided drop dry cooling towers from further consideration for retrofitting at BPS for a combination of reasons. First, although the Agency has not performed an independent review of the costs predicted by the permittee for this alternative, based on our research we believe that the permittee's assertion that this technology would be more expensive is correct. As noted above, EPA has determined that a dry cooling system generally can cost up to three times more to install than a comparable wet cooling system.[120] Second, dry cooling may impose a greater energy penalty.[121] Third, there is substantially more uncertainty about the feasibility (or difficulty) of retrofitting open-cycle generating units to dry cooling than there is with respect to wet cooling, and this uncertainty grows as more units are considered for conversion. In other words, for cooling system options that would address more than one of BPS's generating units, and that therefore could achieve greater thermal discharge reductions than cooling system options that would address only one of BPS's generating units, the feasibility of converting to wet cooling towers is clear, whereas the feasibility of the dry cooling options is not.

In sum, because EPA is evaluating several wet mechanical draft cooling tower options for retrofitting at BPS -- including an option that would address all four generating units -- EPA does not believe that further evaluation of dry cooling at BPS is necessary at this time.

ii. Helper Cooling Towers

Helper cooling towers are another technological alternative for reducing a plant's thermal discharges. These towers supplement an open-cycle cooling system by removing a portion of the heat energy discharged in a plant's effluent and transferring it directly to the atmosphere.

The permittee evaluated the use of helper mechanical draft cooling towers with eight cells, 18 cells, 24 cells, 30 cells and 48 cells for both thermal load and flow reduction at BPS.[122] EPA has selected the permittee's 48-cell helper cooling tower option for detailed evaluation to determine whether it is BAT for controlling thermal discharges from BPS. The conclusions of this evaluation, including an independent analysis of the costs and their reasonableness, is presented below.

iii. "Piggyback" Cooling

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[120] See 65 Fed. Reg. 49081 (August 10, 2000).

[121] See EPA TDD 2001 - New Facilities, Chapter 3 (entitled "Energy Penalties, Air Emissions, and Cooling Tower Side-Effects").

[122] See December 2001 USGenNE 316(a) and (b) Demonstration, Vol. IV, App. H, § 3.2.

The permittee evaluated two "piggyback" cooling options in the January 1997 NEPCO Report and then reevaluated them in the December 2001 USGenNE 316(a) and (b) Demonstration.[123]

According to the permittee, the first piggyback cooling option – "simple" or "conventional" piggyback operation – would involve "routing a portion of the mixed, warm condenser discharge of Units 1, 2, and 3 into the pump bay of Unit 4" for cooling.[124] In other words, this option would transfer the waste heat from Unit 4 to the already heated effluent from Units 1, 2 and 3. Thus, it would not reduce the total heat load discharged to Mount Hope Bay. In fact, under certain conditions, the heated effluent from Unit 4 would exceed current permit limits for maximum temperature and ∆-T, especially during the summer. As a result, implementation of year-round piggyback cooling would require either installation of additional thermal discharge reduction technology or substantial cutbacks in operations.[125] The second piggyback cooling option evaluated by the permittee is a variation on the first option that would reroute the existing Unit 4 intake flow directly to Unit 3. In this option, the flow drawn from the Taunton River for Unit 3 would be replaced with flow from the Lee River withdrawn through the newer Unit 4 CWIS.

EPA has concluded that neither piggyback option could constitute BAT by itself. As noted above, implementing either piggyback option on a year-round basis would render the plant unable to comply with the permit's limitations for maximum temperature and ∆-T unless the permittee either significantly curtailed generation during the summer or installed substantial additional thermal reduction technology. Such curtailment is likely to be quite expensive and is not preferred by the permittee. More important, there is no added benefit to implementing either piggyback option if the permittee will still need to install additional cooling technologies in order to reduce the overall heat discharged to the bay.

iv. **Generation Curtailment**

The permittee also evaluated the use of generation curtailment (i.e., flow reduction) for thermal load and flow reduction at BPS.[126] According to the permittee, this alternative would involve curtailing the generation of electricity to a level that would enable the plant to reduce flow by 29% (i.e., equivalent to eliminating the flow for Unit 4). The permittee indicated that very high energy losses would occur with this alternative on an annual basis, as well as reductions in plant reliability and energy output. Specifically, the permittee asserted that this alternative would

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[123] See id., § 3.4.

[124] Id., p. 3.4-1.

[125] Id.

[126] See January 1997 NEPCO Report, § 4.4.

reduce BPS generation by 300 MW, with a corresponding station energy output reduction by 67,000 MWhr.[127] The overall effect on plant energy output would, of course, depend on the extent to which generation was curtailed.[128] The permittee also states that such generation curtailment would diminish station reliability. These problems would be especially acute during the high demand summer period.

Given that there are available methods of reducing thermal loading to Mount Hope Bay without making major reductions in electrical generation, EPA does not believe this method would constitute BAT for BPS. Generation curtailment may be a suitable method of meeting a special short-term heat reduction target at a particular time of the year. EPA will not establish BAT limits for BPS based on the generation curtailment alternative, but the permittee may use this alternative to meet the final permit requirements if it chooses.

4.3.3 Unit-Specific and Multi-Mode Cooling Tower-Based Options for Reducing Thermal Discharges from BPS

In Section 4.3.2a of this determination document, EPA identified a range of mechanical draft cooling tower-based options, including options proposed by the permittee, that BPS could implement to dissipate heat to the atmosphere rather than discharging it to Mount Hope Bay. (We note that despite our having considered numerous options, there are additional variations that have not been evaluated either by the permittee or EPA.) The Agency then selected for more detailed evaluation the options with the greatest potential to be BAT for reducing thermal discharges from BPS. These include three unit-specific options and one multi-mode option:

- Partial closed-cycle cooling using a 22-cell wet mechanical draft wet cooling tower for Unit 3 alone (the "**Closed-Cycle Unit 3**" option).

- Partial closed-cycle cooling using a 15-cell wet mechanical draft cooling tower for Unit 1 or 2 and a 22-cell wet mechanical draft cooling tower for Unit 3 (the "**Closed-Cycle Units 1 or 2 & 3**" option).

- Closed-cycle cooling using a 30-cell wet mechanical draft cooling tower for Units 1 and 2, a 22-cell wet mechanical draft cooling tower for Unit 3, and a 20-cell wet mechanical draft cooling tower for Unit 4 (the "**Closed-Cycle Entire Station**" option).

- Partial closed-cycle cooling using once-through cooling with four 12-cell helper wet

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[127] Id., p. 4-7.

[128] See id., pp. 4-7 to 4-8, Table 6-1.

mechanical draft cooling towers for Unit 4 (the "**Helper Cooling Tower**" option).

- "Multi-mode" cooling using a 20-cell wet mechanical draft cooling tower in partially closed-cycle, helper and piggyback mode for Units 3 and 4 (the "**Enhanced Multi-Mode**" option).

EPA believes this range of unit-specific and multi-mode options is reasonable and appropriate in terms of thermal load reduction, cost and overall environmental impact. The unit-specific options would use cooling towers that are engineered to work with particular generating units. They include both single-unit and multiple-unit alternatives. The Closed-Cycle Unit 3 option would provide the greatest thermal discharge reduction of any possible single-unit option because Unit 3 has the highest temperature rise and design flow of the four units at BPS.[129] The Closed-Cycle Units 1 or 2 & 3 option would provide an intermediate level of thermal discharge reduction and cost (as well as flow reduction).[130] The Closed-Cycle Entire Station option would offer the greatest thermal load reduction, but it is also the most expensive option and would pose the greatest non-water quality environmental and energy-related impacts. As discussed below, fitting any of these options with the capability to by-pass the cooling towers and run in once-through cooling mode might add cost in terms of piping and pumping, but it would enable the permittee to avoid generating unit outages due to vapor plume-related hazards.[131]

The Helper Cooling Tower option would provide a level of thermal discharge reduction similar to that provided by the Enhanced Multi-Mode option (i.e., an annual heat load discharge of 28 TBTU for the Helper Cooling Tower option versus 27.2 TBTU for the Enhanced Multi-Mode option). The Enhanced Multi-Mode option would use cooling towers that could operate in either closed-cycle, "helper" or "piggyback" modes. These towers would be able to provide thermal discharge reductions even if particular generating units were not in operation because they could cool the hot water from other units that *were* in operation; the unit-specific cooling towers would provide no such benefit when the associated generating unit is not operating. EPA believes that the permittee should be commended for developing the Enhanced Multi-Mode option, which is a particularly flexible approach to retrofitting cooling towers to an existing, once-through cooling system. This option provides an additional point on the continuum of thermal load reductions

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[129] See December 2001 USGenNE 316(a) and (b) Demonstration, Vol. IV, App. H, p. 2-2. Although Unit 4's temperature rise and flow are close to Unit 3's, Unit 3 operates far more frequently than Unit 4. Id., pp. 2-2, 3.3-28.

[130] See SAIC, "Evaluation of Additional Cooling Water Technology Alternatives for USGen New England Brayton Point Station" (March 25, 2002) (hereinafter "SAIC Report (March 25, 2002)"), p. 12.

[131] See SAIC Report (March 15, 2002), Table 5.

and costs for the wet mechanical draft cooling tower alternatives.

4.3.4 The Technological Availability of the Unit-Specific and Multi-Mode Cooling Tower-Based Options for Reducing Thermal Discharges from BPS

Based on its own research and analysis and on information submitted by the permittee, EPA has determined that as a general matter, mechanical draft cooling towers are technologically available for retrofitting at BPS. Such cooling towers have been designed and installed to work effectively in cooling systems using salt or brackish water, as BPS's existing cooling system does.[132] Moreover, experience at other plants has shown that closed-cycle mechanical draft cooling towers can be retrofitted to an existing once-through power plant.[133] Indeed, as noted above, the permittee has not argued that such a retrofit would be unfeasible. Finally, EPA and the permittee agree that there is adequate space at BPS to install a closed-cycle mechanical draft cooling tower system, although space becomes increasingly limited as more cooling tower cells are added.[134] Therefore, the remainder of this determination document presents EPA's BPJ-based analysis of what mechanical draft cooling tower technology or technologies may constitute BAT under CWA §§ 301(b)(2) and 304(b)(2) and 40 C.F.R. § 125.3(d)(3) at BPS.

EPA currently uses BPJ to set BAT limits for thermal discharges from individual facilities in the steam electric power generating source category, which includes BPS.[135] As discussed in detail in

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[132] See, e.g., December 2001 USGenNE 316(a) and (b) Demonstration, Vol. IV, App. H, p. 3-2 ("[s]ince the 1970s, a large number of successful, reliable salt water cooling towers have been installed," mostly in southern and western United States); EPA TDD 2002 - Existing Facilities, p. 401; December 20, 2001 e-mail from Timothy Connor, EPA Headquarters, to Mark Stein, EPA Region 1.

[133] See Memorandum from Nick Prodany and Mark Stein to Brayton Point NPDES Permit File, "Notes on Telephone Call with Engineer at Canadys Station power plant in South Carolina;" December 12, 2001 memorandum from Mark Stein to Brayton Point NPDES Permit File ("Brief Notes on an Issue Discussed During Conference Call with John Gulvas of Consumers Energy and the Palisades Nuclear power station in Covert, Michigan"); January 1997 NEPCO Report, p. 3-6; December 18, 2001 e-mail from Timothy Connor, EPA Headquarters, to Mark Stein, EPA Region 1.

[134] See December 2001 USGenNE 316(a) and (b) Demonstration, Vol. IV, App. H, §§ 3.3, 3.3.5, 3.3.6 and Figure 3.3-1.

[135] See, e.g., In the Matter of Public Service Co. of New Hampshire (Seabrook Station, Units 1 and 2), NPDES Appeal No. 76-7, 1977 WL 22370, *6 (E.P.A.), 1 E.A.D. 332 (1977) ("The effect of the remand of the steam electric generating guidelines was ... to require the

Section 4.2 above, BAT limits represent the minimum allowable level of treatment for toxic and non-conventional pollutants based on control techniques that are "technologically available" and "economically achievable," and that will result in "reasonable progress" toward the elimination of the discharge of such pollutants.[136] To determine whether a particular control technique is technologically available, EPA is required to consider "the age of the equipment and facilities involved, the process employed, the engineering aspects of the application of various types of control techniques [and] process changes."[137]

In accordance with the CWA, EPA considers each of these factors below to determine whether one or more of the unit-specific or multi-mode wet cooling tower options described above is technologically available for BPS. It evaluates the electric power generation and existing cooling water intake and discharge processes currently employed at BPS, engineering aspects of implementing each wet cooling tower option at the plant, and the process changes that would be necessary for implementation of each option. It also evaluates how the age of the plant's electric power generation units and existing cooling system infrastructure affects the cost and feasibility of retrofitting the various wet cooling tower options at the plant.

4.3.4a The Electric Power Generation, Cooling Water Intake and Cooling Water Discharge Processes Currently Employed at BPS

BPS covers approximately 250 acres at the confluence of the Taunton and Lee Rivers. Four fossil-fueled electric power generating units are contained in boiler and turbine houses, which are connected in line to form the power plant. Maintenance facilities, laboratories and administrative offices are attached to the east side of the plant. Three 350-foot stacks for Units 1, 2, and 3, one 500-foot stack for Unit 4, and five fuel oil storage tanks with a combined capacity of 1,386,000 barrels are located south of the plant. A nine-acre, 600,000 ton-capacity coal storage area is located east of the oil storage area. A dredged channel is located along the west side of the coal storage area for ships delivering fuel to the station.

A spray cooling canal for Unit 4 condenser cooling water was built north of the plant but is now mostly filled in with structural fill from the coal units. Within the remains of the cooling canal loop are two wastewater treatment basins. Adjacent to the canal on the west and north sides are wastewater treatment sludge disposal trenches. Also on the north side of the plant and east of the

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Agency to determine what is [BAT] for existing sources on a case-by-case basis under Section 402(a)(1).").

[136] See CWA §§ 301(b)(2)(A), 304(b)(2)(B), 33 U.S.C. §§ 1311(b)(2)(A), 1314(b)(2)(B).

[137] CWA § 304(b)(2)(B), 33 U.S.C. § 1314(b)(2)(B). See also 40 C.F.R. § 125.3(d)(3).

former spray cooling canal are transmission lines, which run northeasterly off the station site onto a company right-of-way.

The four boilers inside the plant (one for each unit) utilize coal, No. 6 fuel oil or gas. Units 1, 2, and 3 were put in service in August 1963, July 1964, and July 1969, respectively. They were originally designed to burn coal but were converted to burn oil in 1969. The units were converted back to burn coal in early 1982. Unit 4, designed to burn oil, was put into service in December 1974, with gas-fired capability added in 1992.

A once-through condenser cooling system with a design flow of 640,000 gpm is currently used for Units 1, 2 and 3. The condenser cooling system for Unit 4, originally closed-cycle, was converted to once-through operation with a design flow of 260,000 gpm beginning in July 1984. An additional once-through flow of 31,000 gpm is currently used by all four units for cooling water and other plant uses (e.g., service water).

A cooling water intake embayment for Units 1, 2 and 3 is located on the eastern side of the station and consists of six intake bays (two for each intake). Each intake bay extends to a depth of approximately 20 feet below mean sea level (msl) and is equipped with a trash rack, a traveling screen, a circulating water pump and a conduit through which water is pumped to a condenser. A design flow of 671,000 gpm of salt water (once-through cooling water plus service water) is pumped from the Units 1, 2, and 3 intake basin.

For Unit 4, an angled screen intake consisting of a reinforced concrete structure 145 feet long, with a 111.5-foot entrance width and a 61.5-foot exit width, is located on the northern side of the station. Cooling water enters this structure through eight 11-foot-wide openings that extend from 18.0 feet below msl to the bottom of a curtain wall 4.0 feet below msl, and that are shielded by trash racks. Tied-back sheet pile walls extend from each end of the trash rack faces, preventing any pocket from being formed by the structure and the shoreline that might impede fish movement. A design flow of 273,788 gpm is drawn through the bar racks. About 265,710 gpm is drawn through the screens at varying velocities, with a portion being used for screenwash; the remainder is pumped through the fish by-pass.

Condenser cooling water for each unit and service water for the station are currently discharged on the west side of the plant site and directed through a discharge channel to upper Mount Hope Bay. The 3,200-foot long discharge channel terminates at the southern tip of the plant site at a venturi designed to promote rapid mixing with the surrounding cooler water. A barrier net has been installed near the end of the discharge channel in a sometimes unsuccessful effort to block fish from entering the channel from Mount Hope Bay.[138]

4.3.4b Engineering Aspects of Implementing the Unit-Specific and Multi-Mode Cooling Tower-Based Options at BPS

In the December 2001 USGenNE 316(a) and (b) Demonstration, the permittee describes the basic design of a mechanical draft cooling tower system that could be implemented to disperse waste heat to the atmosphere at BPS, whether in closed-cycle, helper or multi-mode operation. In this cooling tower design:

- Water from the condenser of each affected generating unit would be pumped to one or more multi-cell induced-draft counter-flow towers, to an elevation of about eight feet above the tower air inlet located on the periphery of the tower cells.

- The heated water would be distributed evenly and dispersed over the top of a heat transfer section in each tower cell. It then would fall by gravity through the heat transfer section into a basin at ground level, where it would be collected and either returned to the condensers or discharged to the discharge canal.

- As the heated water flows down in a film on the surfaces of the heat transfer fill section, it would be cooled by air contact and evaporation of a small portion of the water into the ambient air, which would be simultaneously induced to flow upwards in the opposite direction of the falling water.

- In each cell, this upward airflow would be produced by the action of a large-diameter induced-draft fan situated above the heat transfer section and drift eliminators. A large electrical motor would drive each of the fans.

- After passing through the tower cell's heat transfer section, the air would move through drift eliminators where almost all of the entrained droplets of circulating water would be removed for return to the tower basin. The air would exhaust from the tower at a temperature slightly below that of the initial condenser discharge.[139]

As the permittee explains, it is "[t]he method of piping the cooling tower to the existing circulating water system to receive heated water and discharge cooled water [that] determines

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[138] December 2001 USGenNE 316(a) and (b) Demonstration, Vol. IV, App. H, pp. 2-1 to 2-7; SAIC Report (March 15, 2002), pp. 2 to 4.

[139] See December 2001 USGenNE 316(a) and (b) Demonstration, Vol. IV, App. H, p. 3-2.

whether it is a conventional closed-cycle tower, a helper tower or a multi-mode tower."[140] In a full or partial closed-cycle configuration, the cooling tower would be permanently connected to one or more of the generating units at the plant and thus would be an integral operating component of the unit or units; in a helper configuration, rather than being connected to any of the generating units, the same tower would be an add-on at the end of the cooling cycle, while in a multi-mode configuration, the tower would be connected to one or more of the generating units but not in a permanent manner, thus allowing power production even when the tower is shut down.[141]

Each of the unit-specific and multi-mode options considered below for BPS incorporates this basic wet cooling tower design.

i. The Closed-Cycle Unit 3 Option

The Closed-Cycle Unit 3 option involves converting Unit 3 to closed-cycle cooling by installing a 22-cell mechanical draft cooling tower. This tower would be arranged in two rows of cells, 11 cells each back to back, and located on the elevated structural fill area north of the generating units and west of the transmission lines. It would be of the induced-draft, counter-flow design described above and would have the following design parameters:

- Flow	280,000 gpm
- Water inlet temperature	103.5ºF
- Water outlet temperature	85ºF
- Ambient temperature	77ºF wet bulb
- Sea water	Filtered but not chemically treated

The Unit 3 cooling tower circulating water system would operate by gravity from the cooling tower basins, through the condensers to a pumping facility downstream of the condensers that would pump the heated discharge back to the cooling tower fill to be cooled. According to the permittee, the gravity flow configuration would be necessary so as not to exceed design pressures of the condensers and existing circulating water conduit, which would be used to the maximum extent in the converted systems.

The cooling tower fill would be made of polyvinyl chloride (PVC) and be a low-fouling or open type. The circulating water distribution system would be located just above the fill. It would be an array of headers and laterals with spray nozzles designed to evenly distribute heated water to the fill with a minimum hydraulic head loss. The system would be low-pressure, with an open

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[140] Id.

[141] See id.

basin, flume-box or several standpipes to avoid overpressurization. The spray nozzles would be large enough to prevent fouling.

The drift eliminator would be located above the circulating water distribution system. It would be a layer of PVC louvers, designed to prevent droplets of hot water from being carried out with the air flow. Above the drift eliminator would be the plenum, roofed by the fan deck. The fan deck would support the fan, fan stack and driving motor. The motor would be located outside of the fan stack on the fan deck and would be mechanically connected to a right-angle gear box at the center of the fan stack on which the fan hub is mounted. The fan would draw the moist air up from the plenum and exhaust it through the stack. The following are key fan data:

- Number of fans:	22
- Fan motor rating:	200 hp
- Total fan power:	3,300 kW
- Fan diameter:	28 ft
- Fan stack discharge diameter:	32 ft
- Design fan air flow:	1,365,000 ft^3/min per fan

The cool water would flow by gravity from the cooling tower basin to condenser inlet conduits. The required basin curb elevation would be +40 ft msl to provide adequate head for gravity flow through the condenser. The required basin minimum depth would be five feet to provide four feet of working water level depth and one foot of freeboard above maximum level.

Freeze protection for cold weather operation would be provided by a cooling tower by-pass system in the cooling tower. The tower by-pass system would consist of two motor-operated butterfly valves that would allow heated water from the supply headers into the basin without its passing through the water distribution system or fill. In cold weather, natural convection from the basin may provide sufficient cooling to run Unit 3 without the use of the fill and operation of the fans. In addition, the warmth of the natural convection would prevent ice damage in the fill and distribution system.

The plan dimensions of the Unit 3 cooling tower would be approximately 594 feet long by 108 feet wide. The structural fill on which the cooling tower would be built is at grade elevation +30 feet msl. The tower basin would extend ten feet above grade. The height of the tower would be 41 feet from basin curb to fan deck, plus 14 feet for the fan stack. The total cooling tower height would therefore be 65 feet above grade and the top of the fan stack would be at elevation +95 feet msl. Approximately three feet of additional structural fill would be required under the cooling tower basin to support the tower at the required elevation.

Make-up and blow-down flow using salt water are calculated to maintain concentration in the circulating water at 1.5 cycles of concentration or less.[142] The design meteorological conditions are 77ºF and 50% relative humidity. Required make-up water flow would be 15,000 gpm, while required blow-down flow would vary from 10,000 to 15,000 gpm depending on unit load and meteorological conditions.

Unit 3 currently uses 290,000 gpm of cooling and service water from Mount Hope Bay. Most of this water is used for once-through cooling. Converting Unit 3 to closed-cycle cooling using a wet mechanical draft cooling tower as the permittee has described would reduce the total Unit 3

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[142] Closed-cycle cooling towers require the continual addition of "make-up" water to the cooling cycle to replace the water lost to the evaporative cooling process and to maintain water chemistry. According to the permittee, in the case of salt water closed-cycle cooling towers, make-up flow must be three times the maximum predicted evaporation rate to maintain concentration of impurities in the cooling cycle to 1.5 times or less to prevent scale formation in the system. With fresh water or gray water closed-cycle cooling towers, concentrations of impurities can be higher, reducing the volume of make-up water needed. See id. at p. 3.3-1.

The permittee evaluated two potential sources of make-up water for the closed-cycle cooling options it evaluated in the December 2001 USGenNE 316(a) and (b) Demonstration: seawater from Mount Hope Bay, and treated sewage effluent ("gray water") from the Fall River, Massachusetts publicly owned treatment works (POTW). The Fall River POTW discharges an average annual daily flow of approximately 20 MGD to Mount Hope Bay that could be used for cooling water purposes. The POTW is located across the bay, and construction of a pipeline to transport the gray water to the plant would be required. The permittee concluded that such a pipeline would be feasible. See id., pp.3.3-1, 3.3-20 to 3.3-24. EPA, however, believes it could raise sensitive environmental issues and permitting uncertainties.

The permittee ultimately concluded that while both cooling towers and support facilities for the gray water option could be accommodated in the BPS site layout, the Fall River POTW would not be able to provide enough gray water to support full power, full closed-cycle operation for the entire station in the summer months. It could provide enough gray water during the summer months to support Units 1 and 2 alone closed-cycle, Unit 3 alone closed-cycle, or Unit 4 alone closed-cycle, but not any combination of these cooling options. The permittee concluded that this was a fatal flaw for the gray water make-up water option. In addition, the permittee estimates that this option would add an additional $29 million in capital costs. EPA believes that the gray water option could provide some potential benefits for reducing water withdrawals from Mount Hope Bay. Nevertheless, based on current information, we are not convinced that the option is feasible because of the limited and variable volume of gray water available from the POTW (especially during the summer), and the permitting and environmental issues related to the pipeline crossing of the bay. See id., pp. 3.3-21 to 3.3-22.

intake flow to 25,000 gpm of makeup and service water flow from Mount Hope Bay, which would correspond to a 28% reduction in the total potential station circulating cooling water flow. The permittee estimates that the Closed-Cycle Unit 3 option would reduce the total annual heat discharge from BPS to **23 TBTU**, which would constitute a **45% reduction** from the current discharge under MOA II.[143]

ii. The Closed-Cycle Units 1 or 2 & 3 Option

The Closed-Cycle Units 1 or 2 & 3 option involves installing a 15-cell mechanical draft cooling tower at Unit 1 or 2 and a 22-cell mechanical draft cooling tower at Unit 3.

EPA developed this option with the expert assistance of its consultant SAIC for the purpose of comparing it with the other unit-specific and multi-mode cooling tower-based options under consideration as potential BAT for reducing thermal discharges from BPS. To the greatest extent possible, SAIC used the same design parameters to develop the Closed-Cycle Units 1 or 2 & 3 option that the permittee used to develop the Closed-Cycle Unit 3 option (discussed above) and the Closed-Cycle Entire Station option (discussed below) presented its December 2001 USGenNE 316(a) and (b) Demonstration.[144]

Retrofitting Units 1 or 3 and Unit 3 with closed-cycle mechanical draft cooling towers would reduce the total annual heat discharge from BPS to Mount Hope Bay to **14 TBTU**, which would constitute a **66% reduction** from the current discharge under MOA II.[145]

iii. The Closed-Cycle Entire Station Option

The Closed-Cycle Entire Station option involves installing a 30-cell mechanical draft cooling tower at Units 1 and 2, the 22-cell mechanical draft cooling tower described above at Unit 3, and a 20-cell mechanical draft cooling tower at Unit 4.[146]

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143 See id., pp. 3.3-9 to 3.3-14.

144 See SAIC Report (March 25, 2002), pp. 6-7, 9-12 and Figure 3.

145 See id., p. 19 (Table 8).

146 See December 2001 USGenNE 316(a) and (b) Demonstration, Vol. IV, App. H, pp. 3.3-3 to 3.3-8, 3.3-15 to 3.3-19.

The permittee notes that in its proposal for converting the entire station to closed-cycle cooling, the closed-cycle cooling system for each unit is designed so that its installation

Units 1 and 2. The Units 1 and 2 tower would be located on the elevated structural fill area north of the generating units and west of the transmission lines. It would be arranged in two rows of cells, 15 cells each back to back; the easterly row of cells would serve Unit 1, and the westerly row would serve Unit 2. The tower would be of the induced-draft, counter-flow design described above and would have the following design parameters:

- Flow	360,000 gpm
- Water inlet temperature	97.2ºF
- Water outlet temperature	85ºF
- Ambient temperature	77ºF wet bulb
- Sea water	Filtered but not chemically treated

The Units 1 and 2 cooling tower circulating water system would be designed and operated in the same manner as the Unit 3 cooling water circulating system, i.e., by gravity from the cooling tower basins, through the condensers, to a pumping facility downstream of the condensers that would pump the heated discharge back to the cooling tower fill to be cooled. One exception would be the fans, of which there would be 30 with a total fan power consumption of 4,500 kW. Freeze protection for cold weather operation would be provided by the same type of cooling tower by-pass system as in the Unit 3 cooling tower.

The plan dimensions of the Units 1 and 2 cooling tower would be approximately 810 feet long by 108 feet wide. As with the Unit 3 cooling tower, the total height of the Units 1 and 2 cooling tower would be 65 feet above grade, and the top of the fan stack would be at elevation +95 feet msl.

As with the Unit 3 tower, make-up and blow-down flow using salt water are calculated to maintain concentration in the circulating water at 1.5 cycles of concentration or less. The design meteorological conditions are 77ºF and 50% relative humidity. Required make-up water flow would be 4,500 gpm per unit for a total make-up water flow of 9,000 gpm. Required blow-down flow would vary from 3,000 to 4,500 gpm per unit depending on unit load and meteorological conditions.

Units 1 and 2 currently use 376,000 gpm of cooling and service water from Mount Hope Bay.

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would not interfere with the conversion of the other units to closed-cycle cooling. See id., p. 3.3-25. This one-by-one approach to converting all four units to closed-cycle cooling may increase the costs for such general construction tasks as mobilizing equipment to the site and performing necessary grading work by up to four times, because it does not consider the cost and efficiency savings that could be achieved by mobilizing for and performing all the construction tasks at the same time.

Most of this water, about 96%, is used for once-through cooling. Converting Units 1 and 2 alone to closed-cycle cooling using a wet mechanical draft cooling tower would reduce the total Units 1 and 2 intake flow to 25,000 gpm of makeup and service water flow from Mount Hope Bay, which would correspond to a 38% reduction in the total potential station circulating cooling water flow. It would reduce the total annual heat discharge from BPS to **25 TBTU**, which would constitute a **40% reduction** from the current discharge under MOA II.[147]

Unit 4. The Unit 4 tower would be arranged in two rows of cells, 10 cells each back to back, and located on the elevated structural fill area north of the generating units and west of the transmission lines. It would be of the induced-draft, counter-flow design described above and would have the following design parameters:[148]

- Flow	260,000 gpm
- Water inlet temperature	103ºF
- Water outlet temperature	85ºF
- Ambient temperature	77ºF wet bulb
- Sea water	Filtered but not chemically treated

The Unit 4 cooling tower circulating water system would be designed and operated in a similar manner as the Unit 1, 2 and 3 cooling water circulating systems. Cool water would flow by gravity from the cooling tower basin into and through the Unit 4 circulating water system and condenser, and then be discharged into the Units 1-2-3 discharge canal to the east of the tri-bridge; this heated discharge would then be recirculated under tri-bridge arm B through the cooling channel and to the intake for the cooling tower pumping facility, which would pump it back to the cooling tower fill to be cooled. One difference between the Unit 4 cooling tower and the Units 1, 2 and 3 towers would be the fans, of which there would be 20 with a total fan power consumption of 3,000 kW. In addition, the existing Unit 4 circulating water pump structure would be used; however, the installation of new pumps with higher head would be required to pump the heated water up to the cooling tower fill. Freeze protection for cold weather operation would be provided by the same type of cooling tower by-pass system as in the Units 1, 2 and 3 cooling towers.[149]

The plan dimensions of the Unit 4 cooling tower would be approximately 540 feet long by 108 feet wide. As with the Units 1, 2 and 3 cooling towers, the total height of the Unit 4 cooling tower would be 65 feet above grade, and the top of the fan stack would be at elevation +95 feet msl.

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147 See id., pp. 3.3-3 to 3.3-4, 3.3-6.

148 Id., p. 3.3-9.

149 See id., pp. 3.3-15, 3.3-16 to 3.3-17.

As with the Units 1, 2 and 3 towers, make-up and blow-down flow using salt water are calculated to maintain concentration in the circulating water at 1.5 cycles of concentration or less. The design meteorological conditions are 77ºF and 50% relative humidity. Required make-up water flow would be 15,000 gpm, while required blow-down flow would vary from 10,000 to 15,000 gpm per unit depending on unit load and meteorological conditions.

Unit 4 currently uses a maximum of 260,000 gpm of cooling and service water from Mount Hope Bay. Converting Unit 4 alone to closed-cycle cooling using a wet mechanical draft cooling tower would reduce the total Unit 4 intake flow to 25,000 gpm of makeup and service water flow from Mount Hope Bay, which would correspond to a 26% reduction in the total potential station circulating cooling water flow. It would reduce the total annual heat discharge from BPS to **36.6 TBTU**, which would constitute a **13% reduction** from the current discharge under MOA II.[150]

Entire Station. Retrofitting the entire station with closed-cycle mechanical draft cooling towers would reduce the total BPS intake flow from 931,000 gpm to 39,000 gpm, or a 96% reduction in the total potential station circulating cooling water flow. It would nearly eliminate the total annual heat discharge from BPS to Mount Hope Bay, reducing it to **0.8 TBTU at a maximum temperature of 85 °F**, which would constitute approximately a **98% reduction** from the current discharge of 42 TBTU allowed under MOA II.[151]

iv. The Helper Cooling Tower Option

The Helper Cooling Tower option involves installing a 48-cell mechanical-draft cooling tower complex both to "help" in cooling the discharge of Units 1, 2 and 3 and to precool the discharge water supplying the Unit 4 condenser. The tower complex would remove about 69% of the total potential station circulating water flow discharge from the discharge canal, cool it through an approximate 16ºF temperature increase range, and return it to the discharge canal.

The Helper Cooling Tower complex would consist of four back-to-back fiberglass mechanical-draft towers, with both a shoreline and a Unit 4 pumphouse. The tower would be of the induced-draft, counter-flow design described above and would be located in a nine-acre area south of the plant. There would be 48 fans with a total fan power consumption of 7,160 kW. Freeze protection for cold weather operation would be provided by the same type of cooling tower by-pass system that would be used for Unit 4 in the Closed-Cycle Entire Station option.

Each tower would be 110 feet wide by 325 feet long, with a fan deck elevation of 40 feet and a

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[150] Id., pp. 3.3-3 to 3.3-4, 3.3-6.

[151] Id., p. 3.3-25.

fan stack height of ten feet. All four towers would be located behind an earthen berm back from the eastern shore of the existing discharge canal. Because the average elevation of this area is about 35 feet, approximately 250,000 cubic yards of earth would have to be removed in order to locate the towers at the required elevation of approximate grade elevation 18.0 feet. This earth would be used to create the earthen berm as well as other barriers or roadways that would aid in visually blocking the towers. In addition, the permittee would construct double casing siding on the western face of the towers and a low noise attenuation wall atop the berm to mitigate the visual presence of the towers from the Swansea shore.

Retrofitting the Helper Cooling Tower option at BPS would reduce the total station intake flow by 374.5 mgd, which would be a 29% reduction in the total potential station circulating cooling water flow (or equivalent to eliminating the flow of the Unit 4 circulating water system). It would reduce the total annual heat discharge from BPS to Mount Hope Bay to **27.2 TBTU**, which would constitute a **35% reduction** from the current discharge under MOA II.[152]

v. The Enhanced Multi-Mode Option

The Enhanced Multi-Mode option involves installing a 20-cell fiberglass mechanical draft cooling tower and connecting circulating water piping that would operate together either as a closed-cycle tower for Unit 4 and helper tower for Units 1 and 2, or as a closed-cycle tower for all or part load on Unit 3 when Unit 4 is not operating or is operating at reduced load.

The 20-cell tower would be arranged in two rows of ten cells each and located on the structural fill area north of the generating units and west of the transmission lines. It would be of the induced-draft, counter-flow design described above and would have the following design parameters:

- Flow	260,000 gpm
- Water inlet temperature	107ºF
- Water outlet temperature	85ºF
- Helper flow	40,000 gpm
- Ambient temperature	77ºF wet bulb
- Sea water	Filtered but not chemically treated
- Sea water salinity	30,000 parts per million (ppm) or less

The fans would be similar to those used in the unit-specific closed-cycle options, except that there would be 20 of them, with a total fan power consumption of 4,000 kW. The total cooling tower height would be 68 feet above grade, and the top of the fan stack would be at elevation +98

[152] See id., pp. 3.2-15, 3.2-17, 3.2-18.

feet msl. The plan dimensions of the cooling tower would be approximately 540 feet long by 108 feet wide.[153]

The Enhanced Multi-Mode option would allow for system operation in several different modes:

- Effectively closed loop on Unit 4 (Modes 1A and 1C).

- Effectively closed loop on Unit 3 (Mode 1B).

- Helper Cooling on Units 1 and 2 (Mode 1D).

- Piggyback Operation on Unit 4 (Modes 2 and 3).

- Once-through cooling for units operating (Modes 3 and 4).

The following table summarizes these operating modes:[154]

Table 4.3 -1: Enhanced Multi-Mode Option -- Modes of Operation

Mode	Tower Operational	Unit 4 Operational	Unit 3 Operational	Unit 4 Closed-cycle	Closed-Cycle Unit 3	Units 1 & 2 Helper	Unit 4 Piggy Back	Unit 4 Intake Operational
1A	X	X	X	X				
1B	X		X		X			
1C	X	X		X				
1D	X					X		
2		X					X	
3		X	X				X	X
4	X	X	X	X				X

In Mode 1, the cooling tower would be fully operational in either closed-cycle or helper mode. In Mode 2, the cooling tower would not operate, and Unit 4 would operate in piggyback mode using the cooling water discharge from Units 1, 2 and 3. In Mode 3, the cooling tower would not operate, and the Unit 4 intake would operate to limit the discharge temperature. In Mode 4, the tower and the Unit 4 intake would both operate. The plant would operate most of the time in

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153 See id., pp. 3.1-1 to 3.1-2, 3.1-15 to 3.1-16.

154 See SAIC Report (March 15, 2002), Table 3.

Mode 1, with the other modes being used only infrequently.[155] In closed-cycle tower mode, the cooling tower would receive 260,000 gpm of heated water that could be completely from Unit 4, completely from Unit 3, or a combination of the discharge from both Unit 3 and Unit 4. When Unit 3 and Unit 4 are not operating, the cooling tower could receive a portion of Unit 1 and Unit 2's heated discharge in helper mode.[156]

More particularly, the Enhanced Multi-Mode option follows a hierarchy in which cooling water from the cooling tower would be used to cool Unit 4, and would only be used to cool Unit 3 if Unit 4 was not operating or was not utilizing the full cooling capacity of the cooling tower. Thus, it would not be feasible for both Units 3 and 4 to operate in closed-cycle at the same time. The Unit 4 intake would only be operational when both Units 3 and 4 are operational and either the cooling tower is not operating (Mode 3) or Unit 4 is not operating in piggy-back mode (Mode 4). It should be noted that according to the permittee, operation of the Unit 4 intake in Mode 3 is necessary only when the total plant effluent exceeds thermal limits. Operation in Modes 3 and 4 is estimated to occur infrequently (<500 hours/year).[157]

According to the permittee, the Enhanced Multi-Mode option achieves operational flexibility by providing not only this ability to operate in different cooling modes, but also both the ability to shut down the cooling tower and still allow BPS to continue generate power, and the ability to operate the cooling tower as a cooling system for the entire station and not just a particular unit, as in a conventional closed-cycle design.[158]

In all modes of operation provided by the Enhanced Multi-Mode option, the cooling tower inlet water would come from a common area in the discharge canal. The tower would operate in an "open loop," so that the salinity in the tower would be only slightly above the salinity of the once-through cooling water, so no make-up water system would be required. The permittee proposes the use of conventional construction materials suitable for seawater conditions.[159]

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155 Id., pp. 6 to 7.

156 See December 2001 USGenNE 316(a) and (b) Demonstration, Vol. IV, App. H, pp. 3.1-17 to 3.1-19.

157 See SAIC Report (March 15, 2002), p. 7.

158 See December 2001 USGenNE 316(a) and (b) Demonstration, Vol. IV, App. H, pp. 3.1-1, 3.1-16 to 3.1-18.

159 Details about necessary piping, duct-line, cable trays and grading for the Enhanced Multi-Mode option are provided in the December 2001 USGenNE 316(a) and (b) Demonstration. See id., pp. 3.1-4 to 3.1-5. In addition, the permittee proposes construction of a

USGenNE estimates that the Enhanced Multi-Mode option would reduce annual thermal discharge to **28 TBTU** per year, which would constitute a **33% reduction** from the current discharge under MOA II.[160]

The chart below presents a comparison of the unit-specific and multi-mode cooling tower-based options that EPA believes warrant further detailed consideration. It also presents the existing NPDES permit and MOA II for the sake of comparison. The chart looks only at the *annual* thermal rejection to Mount Hope Bay associated with each option. Ultimately, the permit may also address these parameters with daily, monthly, and/or seasonal limitations. Nevertheless, this chart provides a useful gross comparison.

Table 4.3-2: Flow Rate and Heat Load Comparison Chart

Operating Scenario	Flow Rate (MGD)	Annual Heat Load Discharge (TBTU)
Current Permit	1452	97
MOA II	977	42
Closed-Cycle Unit 3	654	22.9
Closed-Cycle Units 1 or 2 & 3	350	14
Closed-Cycle Entire Station (Units 1, 2, 3 and 4)	56 (Intake)	0.8
Helper Cooling Tower	925 (summer)	27.2
Enhanced Multi-Mode (20-cell cooling tower)	650 (annual) (750(summer)/600 (winter))	28

4.3.4c Age of the Equipment and Facilities Involved in Implementing the Unit-Specific and Multi-Mode Cooling Tower-Based Options at BPS

The permittee's 1997 feasibility report concluded that retrofitting closed-cycle cooling at BPS would be a "difficult engineering, design, scheduling, and construction effort due to its

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new road for cooling tower access, which would also serve as a dike or berm to contain spillover from the cooling tower basin. See id., p. 3.1-5.

160 See id., p. 3.2-15, 3.2-17, 3.2-18.

incompatibility with the original station design."[161] The permittee identified several primary reasons for the complexity of such a retrofit project, including:

- The permanence of existing site features and structures.

- The "fundamental technical differences and incompatibilities" between closed-cycle cooling systems and BPS's existing once-through cooling system, e.g., the existing condensers having a maximum design pressure of about 25 psig and closed-cycle condensers having a design pressure of 80 to 90 psig.

- The "difficult canal construction work that would be necessary to accommodate the plant operational requirements."

- The complexity and cost of construction access and flow of job site erection materials due to the "very limited open space" available at BPS and "the topography in the vicinity of the area" proposed for siting the wet cooling towers.[162]

All of these considerations arguably relate to the age of the plant (i.e., "the equipment and facilities involved") in that they need to be addressed because BPS is an existing plant that would require retrofitting, not a new plant at which any potential difficulties could be resolved during the planning process and prior to construction. As the permittee points out, the fact that BPS is already built means that any retrofit project there would need to take into account not only the once-through cooling system components that are already in place and in use at the site, but also the other site structures and features that already exist there, and the limited open space available at the site as a result of those structures and features that are already present.

EPA agrees with the permittee's observation that retrofitting the Closed-Cycle Unit 3 and Closed-Cycle Entire Station options at BPS would be a "difficult engineering, design, scheduling, and construction effort due to [their] incompatibility with the original station design." EPA notes, however, that the permittee does not assert that such a retrofitting project would be infeasible due to any of these considerations. Moreover, in its research for the CWA § 316(b) Phase II Existing Facility proposed rule, EPA identified several other large power plants that have converted from once-through cooling to closed-cycle mechanical draft towers.[163]

4.3.4d Process Changes Required to Implement the Unit-Specific and Multi-

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[161] Id., p. 3.3-1.

[162] Id.

[163] See SAIC Report (March 15, 2002), p. 26 and Attachment A.

Mode Cooling Tower-Based Options at BPS

i. **The Closed-Cycle Unit 3 Option**

As noted above, a 22-cell mechanical draft cooling tower would be required to convert Unit 3 to closed-cycle cooling. Aside from the installation of the tower itself, the primary process change that would be required for the Closed-Cycle Unit 3 option would be the construction of a new circulating water pumping structure downstream of the unit's existing condenser. The Closed-Cycle Unit 3 cooling tower circulating water system would operate by gravity from the cooling tower basin through the condenser to this pumping structure, which would pump the heated discharge back to the cooling tower fill to be cooled. According to the permittee, this gravity flow configuration would be necessary in order not to exceed design pressures of the unit's existing condensers and circulating water conduits.[164]

As the permittee explained in the December 2001 USGenNE 316(a) and (b) Demonstration, in a standard cooling tower circulating water system, the circulating water pumps are located at the cooling tower basin and pump cooled water from the basin through the condenser and back up to the cooling tower fill. However, retrofitting a closed-cycle configuration at Unit 3 would require much more pump head than currently exists with the unit's once-through siphon systems. That is, Unit 3's existing circulating water system and condenser are not designed for the higher pressures that would be generated in this closed-cycle configuration.

For the Closed-Cycle Unit 3 option, therefore, the permittee has proposed to construct new cooling tower pumphouses downstream of the existing condensers, to the north of the turbine buildings in the vicinity of the seal pits. This would require only the new piping from the pumps to the cooling tower, and not the existing circulating water conduits, piping and condenser, to be designed to withstand the higher pressures generated by the new cooling tower pumps. The seal pits would be demolished, because they would not serve any function in the closed-cycle cooling system, and they would be in the way of the new suction piping to the circulating water pumps.[165]

ii. **The Closed-Cycle Units 1 or 2 & 3 Option**

As noted above, the Closed-Cycle Units 1 or 2 & 3 option would require installation of a 15-cell mechanical draft cooling tower at Unit 1 or 2 and a 22-cell mechanical draft cooling tower at Unit

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[164] December 2001 USGenNE 316(a) and (b) Demonstration, Vol. IV, App. H, p. 3.3-9.

[165] See id., pp. 3.3-10 to 3.3-11. Details about circulating water pump house construction and piping for the Closed-Cycle Unit 3 option are provided in the December 2001 USGenNE 316(a) and (b) Demonstration. See id., pp. 3.3-11 to 3.3-12.

3. To the greatest extent possible, SAIC used the same design parameters in developing this option that the permittee used to develop the Closed-Cycle Unit 3 option and the Closed-Cycle Entire Station option presented its December 2001 USGenNE 316(a) and (b) Demonstration.[166] Therefore, the process changes required to implement this option at BPS are the same as the process changes that would be required for the Closed-Cycle Unit 3 option (discussed above) and the Unit 1 or Unit 2 portion of the Closed-Cycle Entire Station option (discussed below).

iii. The Closed-Cycle Entire Station Option

The Closed-Cycle Entire Station option involves installing a 30-cell mechanical draft cooling tower at Units 1 and 2, the 22-cell mechanical draft cooling tower described above at Unit 3, and a 20-cell wet mechanical draft cooling tower at Unit 4.[167]

As with Unit 3, the primary process change that would be required to retrofit Units 1 and 2 with closed-cycle cooling, aside from installation of the 30-cell wet cooling tower, would be the construction of new circulating water pumping structures downstream of the units' existing condensers. This is because, as with Unit 3, operating retrofitted closed-cycle cooling at Units 1 and 2 would require more pump head than currently exists with the two units' once-through siphon systems, and the units' existing circulating water systems and condensers are not designed for the higher pressures that would result from this closed-cycle configuration. The new pumping structures would be constructed in the same area as the new Unit 3 pumping structure, downstream of the existing condensers, to the north of the turbine buildings near the seal pits.[168]

A similar process change would be necessary to retrofit Unit 4 with closed-cycle cooling, with the installation of new circulating water pumps with higher head required to pump the heated water up to the cooling tower fill; however, the existing Unit 4 circulating water pumping structure would be used instead of building an entirely new pumping structure. New vertical wet-pit-type circulating water pumps would replace the existing Unit 4 pumps to provide the required additional head; the existing Unit 4 inlet conduits would be blocked at the pumping structure, and connections between the existing supply conduits to the condenser and a new return header from

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166 See SAIC Report (March 25, 2002), pp. 6-7, 9-12 and Figure 3.

167 See id., pp. 3.3-3 to 3.3-8, 3.3-15 to 3.3-19.

168 See id., pp. 3.3-4 to 3.3-5. Details about circulating water pump structure construction and piping for Units 1 and 2 are provided in the December 2001 USGenNE 316(a) and (b) Demonstration. See id., pp. 3.3-5 to 3.3-6.

the cooling tower basin would be made downstream of these blocks.[169] According to the permittee, minimal modifications to the existing Unit 4 pumping structure would be required.[170]

iv. The Helper Cooling Tower Option

The Helper Cooling Tower option involves installing four back-to-back fiberglass mechanical-draft towers, a shoreline pumphouse to "help" in cooling the discharge of Units 1, 2 and 3, and a Unit 4 pumphouse to precool the discharge water supplying the Unit 4 condenser.[171]

The four cooling towers would be located centrally to the shoreline pumphouse along the plant side of the existing discharge channel. This pumphouse would be designed to draw 620,000 gpm of heated water from the discharge channel and convey it to the cooling towers by means of four vertical wet-pit pumps. The basins of the towers would all be interconnected, either directly or by flumes. This would enable the cooled water from all the tower basins to flow to the southerly tower and be discharged back into the existing discharge channel via a common open channel flume at the south end of the most southerly tower. There, the cooled water would mix with and cool the 280,000 gpm remaining warm circulating water flow from the plant condensers before all the water exited from the discharge channel into Mount Hope Bay.

According to the permittee, the mixing of these two temperature streams and the cooling of the plant discharge would be assured for three reasons: the turbulence of the open channel flume as it intercepts the main plant flow; the lesser buoyancy of the colder cooling tower stream, which would inherently promote instability and mixing; and the length of the remaining run of discharge channel, which would provide a relatively long residence time for the combined flows before their discharge into the bay.

In addition, the basin of the northerly tower would be connected and supply cooled water to the Unit 4 condenser. A pumphouse at the end of the most northerly tower would contain two wet-pit circulating water pumps with two discharges, which would be routed to tie into the separate lines that currently serve each condenser box. The northern two towers would discharge 260,000 gpm of their total 310,000 gpm flow into this new pumphouse, from which the flow then would be pumped to Unit 4. To accomplish this, two new fiberglass circulating water lines would be installed from the pumphouse and extend about 400 feet to a new reinforced concrete box tunnel

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169 See id., pp. 3.3-15, 3.3-16. Details about circulating water pump house construction and piping for Unit 4 are provided in the December 2001 USGenNE 316(a) and (b) Demonstration. See id., pp. 3.3-16 to 3.3-17.

170 Id., p. 3.3-17.

171 Id., pp. 3.2-15, 3.2-17, 3.2-18.

that would tie in to the existing Unit 4 box tunnel. The existing Unit 4 box tunnel would be capped and sealed in the vicinity of the new tie-in to prevent water and/or soil intrusion.[172]

v. The Enhanced Multi-Mode Option

The Enhanced Multi-Mode option involves installing a 20-cell fiberglass mechanical draft cooling tower and connecting circulating water piping that would operate together either as a closed-cycle tower for Unit 4 and helper tower for Units 1 and 2, or as a closed-cycle tower for all or part load on Unit 3 when Unit 4 is not operating or is operating at reduced load.[173]

When either Unit 3 or Unit 4 operates in closed-cycle mode, the cooling tower would receive 260,000 gpm of heated water delivered by the new cooling tower pumps from the eastern section of the cooling canal. Heated water entering this section of the cooling canal could be all from Unit 4, all from Unit 3, or a combination of the discharges of Units 3 and 4. Moreover, when Units 3 and 4 are not operating, a portion of the heated discharge from Units 1 and 2 could be drawn to the cooling tower pumps, passed through the cooling tower operating in helper mode, and discharged to the discharge canal at the existing Unit 3 and/or Unit 4 discharge structure. The heated discharge then would recirculate under tri-bridge arm B, through the eastern section of the inlet channel, and to the intake for the cooling tower pumps. Extending the Units 1 and 2 discharge piping would reduce the mixing of the heated discharge from Unit 3 and/or Unit 4 with the Units 1 and 2 discharge to a minimum.[174]

The following provides more detail: In the Enhanced Multi-Mode option, cooled water would flow by gravity through the existing Unit 3 and/or Unit 4 circulating water system. According to the permittee, the discharge channel would be subject to tide level fluctuations, which in turn would affect the system hydraulic gradient back to the cooling tower basin and require the basin depth and water surface elevation to accommodate these varying hydraulic conditions. As a result, the cooling tower basin depth would have to be 12 feet to accommodate the eight-foot tidal range in the discharge channel, three feet of water in the basin at extreme low tide and one foot of freeboard in the basin at extreme high tide. The basin water surface elevation thus would be +41 feet to provide adequate head to drive the design flow of 260,000 gpm through Unit 4 at high tide (+3.0 feet msl). The total cooling tower height would be 68 feet above grade, and the

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[172] See id., pp. 3.2-15 to 3.2-16. Details about the cooling tower pumps and piping system for the Helper Cooling Tower option are provided in the December 2001 USGenNE 316(a) and (b) Demonstration. See id., pp. 3.2-16 to 3.2-17.

[173] See id., p. 3.1-1.

[174] Id., p. 3.1-19.

top of the fan stack would be at elevation +98 feet msl.[175]

The existing Unit 4 circulating water pumps would be replaced with new cooling tower pumps, which would be located in the existing Unit 4 pumping structure. New piping would be installed to carry the flow from the new cooling tower pumps to the cooling tower fill distribution system, and the existing Unit 4 inlet conduits would be blocked at the pumping structure. New piping from the cooling tower basin would connect to both the Unit 3 and the Unit 4 condenser inlet conduits; valves would be installed in the piping system from the cooling tower basin to allow cooled water from the cooling tower basin to be directed totally to Unit 3, totally to Unit 4, or a portion to each unit.[176]

The Enhanced Multi-Mode option would require the conversion of the western channel of the existing Unit 4 intake canal into a mixing basin. This would both support the Unit 4 intake pump operation and accommodate discharge flows when the cooling tower is operating in helper mode. The design includes installation of new Unit 4 intake pumps, construction of a new dam into which to place these intake pumps and a discharge flume, and modification of the existing Unit 4 intake canal divider wall. In addition, the existing stop-logs in tri-bridge arm A would be removed to allow intake pump flows to discharge through the canal, and to allow discharge flows to the canal when the cooling tower is operating in helper mode.

The eastern channel of the existing Unit 4 intake canal, which is currently used for recirculation when Unit 4 is operating in piggyback mode, would continue to be used for recirculation when Unit 4 is operated in closed-cycle, helper or piggyback mode. It would also be used as the inlet canal for the new Unit 4 cooling tower pumps. The existing stoplogs in tribridge arm B would be replaced by a sliding gate of about half the total height of the stoplogs; this gate would be used to switch operations between closed-cycle mode and piggyback mode.

The existing Unit 4 discharge, south of tri-bridge arm B, would continue in use. The Unit 4 discharge to the discharge channel for Units 1, 2 and 3 would be stratified to allow withdrawal of the warmest water for cooling. The Units 1 and 2 discharge piping would be extended about 460 feet along the bottom of the discharge channel to a point just east of the southern arm of the tri-bridge. This would allow the heated discharge from Unit 3 to flow north through the east arm of the tri-bridge and to the cooling tower pumps without significant mixing with the Units 1 and 2 discharge.[177] The existing discharge channel bottom would be dredged for the conduit, to allow

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[175] Id., p. 3.1-3.

[176] See id., pp. 3.1-18 to 3.1-19.

[177] See id., pp. 3.1-18 to 3.1-19.

passage of the Unit 3 discharge.[178]

As noted above, in all modes of operation, the cooling tower inlet water would come from a common area in the discharge canal. The tower would operate in an open loop, so that the salinity in the tower would be only slightly above the salinity of the once-through cooling water. Conventional construction materials suitable for seawater conditions could be used, and there would be no need for a make-up water system.[179]

4.4 The Economic Achievability of the Unit-Specific and Multi-Mode Cooling Tower-Based Options for Reducing Thermal Discharges from BPS

4.4.1 Background

The permittee has submitted substantial information regarding its estimates of the capital, operation and maintenance (O&M), and other direct and indirect costs of retrofitting closed-cycle and multi-mode cooling at BPS. EPA, based on this information and on its own research and analysis, agrees with the permittee that retrofitting wet cooling towers for all or some of the generating units at BPS would be a complicated construction project involving substantial cost. The complexity and cost would be greatest for retrofitting the entire plant with closed-cycle cooling and correspondingly less for the partial closed-cycle and multi-mode retrofit options.

In particular, the permittee has identified several specific issues relating to the economic impacts of retrofitting wet cooling towers for all or some of the generating units at BPS. First, according to the permittee, converting BPS to closed-cycle cooling from open-cycle cooling would result in "lost annual generation," which refers to "the quantity of additional energy that the pumps and fans and other operating equipment require to power the components of cooling technology."[180] EPA agrees that switching BPS from open-cycle cooling to closed-cycle cooling would marginally decrease the generating efficiency of each converted unit, resulting in a so-called "efficiency penalty." EPA also agrees that the amount of electricity that a converted unit would generate for sale would be further reduced because a certain amount of energy would have to be

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[178] Details relating to cooling tower pumps and necessary piping, duct-line, cable trays and grading for the Enhanced Multi-Mode option are provided in the December 2001 USGenNE 316(a) and (b) Demonstration. See id., pp. 3.1-3 to 3.1-5, 3.1-19 to 3.1-20. In addition, the permittee proposes construction of a new road for cooling tower access, which would also serve as a dike or berm to contain spillover from the cooling tower basin. See id., p. 3.1-5.

[179] See id., p. 3.1-4.

[180] Id., p. 1-16.

used to run the fans and pumps utilized in the related mechanical draft cooling tower, resulting in a so-called "auxiliary power penalty."[181] Each of these penalties would be proportionally less if less than the entire plant were converted to closed-cycle cooling. The permittee has attributed a cost to these penalties, and EPA has considered these components of the cost of retrofitting wet cooling towers at BPS in its economic achievability evaluation.

Second, the permittee asserts, BPS would have to incur a certain amount of downtime for the construction of each of the different wet cooling tower options under consideration. As with the above-described "penalties," the permittee has attributed a cost to these "construction outages," and EPA has considered this component of the cost of retrofitting wet cooling towers at BPS in its economic achievability evaluation. Third, as the permittee correctly notes, wet cooling towers can emit water vapor (as opposed to mist) that after leaving the tower can under certain meteorological conditions condense into water and freeze, causing fog and/or icing concerns on area roadways. In most cases, any icing conditions would be expected to occur only a short distance from the tower, typically on-site.[182] A site-specific analysis by the permittee, however, concludes that cooling towers at BPS would emit a plume of water vapor that under certain meteorological conditions could freeze on a nearby highway, requiring the permittee to shut down the affected units to ensure traffic safety.[183] The permittee has also attributed a cost to these "plume outages," and EPA also considered this component of the cost of retrofitting wet cooling towers at BPS its economic achievability evaluation.

This determination document first presents the permittee's estimates of the capital, O&M, efficiency and auxiliary power penalty, and construction outage costs associated with the Closed-Cycle Entire Station, Closed-Cycle Unit 3 and Enhanced Multi-Mode options. (Plume outages and projected associated costs are discussed further below.) It then presents EPA's independent analysis of these cost estimates, which the permittee provided in the December 2001 USGenNE 316(a) and (b) Demonstration. It also presents EPA's cost estimates for the Closed-Cycle Units 1 or 2 & 3 option and for two variations on the Closed-Cycle Unit 3 and Closed-Cycle Entire Station options: the addition of either by-pass technology to allow operation in once-through mode, or plume abatement technology. Finally, this document presents EPA's determination of the economic achievability of the unit-specific and multi-mode wet cooling tower options under consideration.

4.4.2 The Permittee's Estimated Costs of the Unit-Specific and Multi-Mode

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181 See EPA TDD 2001 - New Facilities, pp. 3-9 to 3-21 and Table 3-2.

182 See 39 Fed. Reg. 36192 (October 8, 1974).

183 See, e.g., December 2001 USGenNE 316(a) and (b) Demonstration, Vol. IV, App. H, p. 3-3.

Cooling Tower-Based Options for Reducing Thermal Discharges from BPS

4.4.2a The Permittee's Estimated Costs of the Closed-Cycle Unit 3 Option

The permittee estimates the capital cost for the Closed-Cycle Unit 3 option to be $56.4 million, including a 10% allowance for indeterminate costs and a 10% contingency.[184] Estimated annual combined maintenance costs, which include fan maintenance, cooling tower basin cleaning, cooling tower fill cleaning and maintenance and pump maintenance costs, are $155,000 per year.

In addition, the permittee estimates the combined lost annual generation from implementing the Closed-Cycle Unit 3 option to be 119,000 MW-hr/yr. This consists of 55,000 MW-hr/year of additional auxiliary power consumption and 64,000 MW-hr/year of steam turbine operating penalties.[185] According to EPA calculations, the 119,000 MW-hr/yr in lost annual generation is approximately 2.8% of Unit 3 output and 1.4% of BPS output; the 55,000 MW-hr/yr in additional auxiliary power consumption is about 1.3% of Unit 3 output and <1% of BPS output, and the 64,000 MW-hr/yr in steam turbine operating penalties is about 1.5% of Unit 3 output and <1% of BPS output.[186] EPA notes that auxiliary power consumption for this option would be lower than for the Enhanced Multi-Mode option, although the operating penalty is greater. Operating a unit in closed-cycle mode causes an increase in temperature and pressure, which results in lower electricity generation. On the other hand, the Enhanced Multi-Mode option requires increased pumping, which utilizes more power.[187]

Under the permittee's proposed schedule, implementation of the Closed-Cycle Unit 3 option would take about 29 months, with one year required for permitting and engineering commencing eight months into the permitting cycle. A minimum eight-month construction outage starting 20 months into the schedule would be required, and according to the permittee, a replacement would be required for the lost generation of Unit 3 for the period when the plant is shut down for

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[184] See id., p. 3.3-13. According to SAIC, the 10% allowance for indeterminate costs and 10% contingency appear to be somewhat high but not unreasonable. Typically, contingency allowances for heavy industrial projects range between 4% and 7%. However, site-specific factors may increase these factors. See SAIC Report (March 15, 2002), p. 7.

[185] See December 2001 USGenNE 316(a) and (b) Demonstration, Vol. IV, App. H, pp. 3.3-12 to 3.3-14.

[186] See SAIC Report (March 15, 2002), p. 8. This calculation is based on an annual average generation of 8,633,051 MW-hr/yr for the entire station, and 4,318,412 MW-hr/yr for Unit 3, from 1997 through 1999. See id.

[187] See id.

construction of the cooling tower and circulating water pumphouse.[188]

4.4.2b The Permittee's Estimated Costs of the Closed-Cycle Entire Station Option

The permittee estimates the capital cost for the Closed-Cycle Entire Station option to be $177 million, including a 10% allowance for indeterminate costs and a 10% contingency.[189] It arrived at this estimate by adding the estimated costs of converting the four individual units to closed-cycle mode. As a result, the permittee likely overestimates the capital costs of the Closed-Cycle Entire Station option, because it fails to consider the economy of scale that would result from combining the component unit-specific options that make up this option. In its economic achievability analysis, which is described in detail below, EPA estimated an economy of scale of approximately 6% based on the costing methodology used in the development of the CWA § 316(b) Phase I New Facility final rule and Phase II Existing Facility proposed rule.[190]

Estimated annual combined maintenance costs are $475,000 per year. In addition, the permittee estimates the combined lost annual generation to be 286,000 MW-hr/yr.[191] According to EPA calculations, this is approximately 6.6% of average annual generation.[192]

Under the permittee's proposed schedule, overall implementation of the Closed-Cycle Entire Station option would take about 47 months, with one year required for permitting and engineering commencing eight months into the permitting cycle.[193]

4.4.2c The Permittee's Estimated Costs of the Helper Cooling Tower Option

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188 See December 2001 USGenNE 316(a) and (b) Demonstration, Vol. IV, App. H, p. 3.3-14.

189 See id., p. 3.3-26.

190 See SAIC Report (March 15, 2002), pp. 4, 13 (referring to EPA TDD 2001 - New Facilities).

191 See December 2001 USGenNE 316(a) and (b) Demonstration, Vol. IV, App. H, p. 3.3-26.

192 See SAIC Report (March 15, 2002), p. 9. This calculation is based on an annual average generation of 8,633,051 MW-hr/yr for the entire station from 1997 through 1999. See id.

193 See December 2001 USGenNE 316(a) and (b) Demonstration, Vol. IV, App. H, p. 3.3-26.

The permittee estimates the capital cost for the Helper Cooling Tower option to be $98.9 million, including a 10% allowance for indeterminate costs and a 10% contingency. Estimated annual maintenance costs are $300,000 per year. In addition, the permittee estimates combined lost annual generation to be 152,148 MW-hr/year. This consists of 112,875 MW-hr/yr off additional auxiliary power consumption and 39,275 MW-hr/yr of steam turbine operating penalties.

Under the permittee's proposed schedule, implementation of the Helper Cooling Tower option could take about 35 months, with one year required for permitting and engineering commencing seven months into the permitting cycle. Construction would commence 14 months into the schedule. Only two one-month construction outages would be required. According to the permittee, most of the required construction would not interfere with station operation.[194]

4.4.2d The Permittee's Estimated Costs of the Enhanced Multi-Mode Option

The permittee estimates the capital cost for the Enhanced Multi-Mode option to be $57.4 million, including a 10% allowance for indeterminate costs and a 10% contingency. Estimated annual maintenance costs are $240,000 per year. In addition, the permittee estimates combined lost annual generation to be 97,900 MW-hr/yr. This consists of 72,600 MW-hr/year of additional auxiliary power consumption and 25,300 MW-hr/year of steam turbine operating penalties.[195] According to EPA calculations, this is approximately 1% of average annual generation.[196]

Under the permittee's proposed schedule, implementation of the Enhanced Multi-Mode option could take about 31 months, with one year required for permitting and engineering commencing seven months into the permitting cycle. Construction would commence 15 months into the schedule. A construction outage of approximately four months duration for Unit 4, starting 27 months into the schedule, and shorter construction outages of two to three weeks for Units 1 and 2 at 19 months into the schedule and for Unit 3 at 24 months, would also be required.[197] system.[198]

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[194] Id., p. 3.2-18.

[195] See id., p. 3.1-22.

[196] See SAIC Report (March 15, 2002), p. 7. This calculation is based on an annual average output of 8,633,051 MW-hr/yr for 1997 through 1999. See id.

[197] December 2001 USGenNE 316(a) and (b) Demonstration, Vol. IV, App. H, p. 3.1-22.

[198] See id., p. 3.1-4.

4.4.3 EPA's Independent Evaluation of the Permittee's Estimated Costs of the Unit-Specific and Multi-Mode Cooling Tower-Based Options for Reducing Thermal Discharges from BPS

EPA hired two contractors, Science Applications International Corporation (SAIC) and Abt Associates, Inc. (Abt), to provide expert analysis in support of the Agency's independent evaluation of the estimated costs of the cooling tower-based options under consideration to be BAT for reducing thermal discharges from BPS into Mount Hope Bay. These contractors addressed issues relating to what EPA has labeled the "engineering aspects" and "financial aspects" of the economic achievability analysis required under the CWA to establish BAT limits.

First, EPA retained SAIC, under subcontract to Tetra Tech, Inc., to assess "engineering aspects" of the estimated costs of the unit-specific and multi-mode cooling tower-based options under consideration. These include the capital and annual costs of each option, with annual costs including O&M costs, the cost of any reduction in electrical generation efficiency resulting from implementation of the particular option (i.e., the "efficiency penalty" associated with the option), and the cost of the auxiliary power needed to run the option (i.e., the "auxiliary power penalty" associated with the option). SAIC reviewed and evaluated the permittee's capital and annual cost estimates for its Closed-Cycle Unit 3, Closed-Cycle Entire Station and Enhanced Multi-Mode options and compared them against published capital and O&M costs available from industry and construction standards, vendor quotes, information collected and developed in support of the 316(b) Phase I New Facility final rule and 316(b) Phase II Existing Facility proposed rule, and knowledge of experienced personnel.[199] Then, SAIC developed its own independent engineering cost estimates for the permittee's Closed-Cycle Unit 3, Closed-Cycle Entire Station and Enhanced Multi-Mode options. Finally, SAIC estimated the capital costs of equipping the cooling towers associated with the Closed-Cycle Unit 3 and Closed-Cycle Entire Station options with the pumping and piping that would allow them to be by-passed, so that the generating units could be run in once-through mode (thus eliminating any need for generating unit shutdowns), and with plume abatement technology (based on traditional wet/dry hybrid cooling) instead of multi-mode technology.

The "engineering aspects" of the costs of the various cooling tower-based options also include the extent to which one-time power generation unit outages could be necessary to enable installation of particular cooling options (i.e., the "construction outage" associated with the option). SAIC evaluated this aspect of the options' costs because the permittee's cost estimates include the cost of the power generation lost as the result of such construction outages. Finally, SAIC evaluated the likely construction schedule for each option on the grounds that scheduling has a direct bearing on cost.

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[199] See SAIC Report (March 15, 2002), p. 2.

Second, EPA retained Abt to assess "financial aspects" of the estimated costs of the unit-specific and multi-mode cooling tower-based options under consideration for BPS. In performing this assessment, Abt developed a model to determine three financially significant elements of each option: the cost to the permittee over time, the net present value of this multi-year cost, and the equivalent annualized cost. This analytical approach mirrors that which the permittee used in its "Dynamic Cost Analysis."[200] Thus, the results of Abt's analysis can be meaningfully compared with the results of the permittee's analysis.[201]

Abt's analysis not only considered the capital costs and annual O&M costs for the cooling tower-based options under consideration, but also determined the cost of each of these options to the permittee in terms of lost revenue due to reduced electrical generation. These lost generation-related costs include both construction outages and annual losses resulting from efficiency and auxiliary power penalties. In addition, Abt's analysis took into account the cost to the permittee of generating unit outages that the permittee predicts would be required to address vapor plume-related icing and fogging safety issues (i.e., the "plume outages" potentially associated with each option). Finally, Abt's analysis considered the *increased* revenues that the permittee would be able to obtain based on the extent to which each option would enable increased hours of operation during peak summer demand periods as a result of reduced discharge temperatures.

With SAIC and Abt's expert assistance, EPA carefully considered the economic analyses that the permittee presented in the December 2001 USGenNE 316(a) and (b) Demonstration.[202] We and the contractors also considered a substantial amount of additional information earlier submitted by the permittee, including, without limitation, the January 1997 NEPCO Report; various meeting handouts from the permittee, and materials submitted by the permittee in response to EPA CWA

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[200] See December 2001 USGenNE 316(a) and (b) Demonstration, Vol. III, App. G (Tab: Dynamic Cost Analysis). EPA and the permittee have agreed that this type of analysis is the most accurate way to assess the cost to the permittee of each option, as opposed to, for example, the "static cost analysis" approach that the permittee had used in several submissions prior to the December 2001 USGenNE 316(a) and (b) Demonstration.

[201] To generate its own independent cost estimates for EPA, Abt used "engineering cost" data from the reports that SAIC prepared. Where SAIC either did not develop an independent value or determined that the permittee's data appeared reasonable, Abt used inputs based on the permittee's analysis. All of this is described in detail in the Abt report. See Abt, "Cost Analysis of Alternative Technology Options for Management of Thermal Discharge and Cooling Water Intake for Brayton Point Station (April 5, 2002) (hereinafter "Abt Report").

[202] In particular, in evaluating the cost issues EPA and the contractors considered Volume III, App. G (Tab: Dynamic Cost Analysis) and Volumes IV, V and I (Executive Summary) of the December 2001 USGenNE 316(a) and (b) Demonstration.

§ 308 information request letters.[203] The latter materials include data submitted by the permittee from Resource Data International as well as information submitted with an October 16, 2001 letter from the permittee's counsel, Wendy Jacobs of Foley, Hoag & Eliot, LLP, to Mark Stein of EPA. In addition, EPA and the contractors had several meetings and conference calls with the permittee and its consultants to discuss factual and analytical issues related to the assessment of the costs of the options. Finally, the contractors did substantial research using a variety of sources of data independent from the permittee. These independent sources are described and referenced in the contractors' reports.

EPA has independently reviewed the reports submitted by SAIC and Abt and determined them to contain reasonable and appropriate analyses. As explained in the reports, these analyses are conservative in many important respects (e.g., both SAIC and Abt structured their analyses so as to produce higher cost estimates). Therefore, EPA adopts the analyses contained in the SAIC and Abt reports and incorporates these reports by reference into this BAT determination. The SAIC and Abt reports are available in the administrative record.

In general, EPA has concluded that the permittee has substantially overestimated the likely costs of the various closed-cycle and multi-mode cooling tower-based options. The primary driver for this overestimation is the permittee's inflated capital cost predictions, but the permittee's excessive predictions regarding construction outages, energy efficiency penalties and plume outages also materially contribute to the total overestimate. In addition, the permittee's overestimate of the costs of the options is affected by other aspects of its financial analysis, such as its choice of discount rate, certain inappropriate tax treatments,[204] and its unrealistic use of 2001 as the starting date for construction of new facilities. Key points and conclusions from EPA's independent evaluation are presented below.

4.4.3a "Engineering Aspects"

i. Capital Costs

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[203] It should be noted that the permittee's analysis of the cost of various cooling options has changed significantly over time. For example, the January 1997 NEPCO report estimated that the option of closed-cycle mechanical draft wet cooling towers for Unit 4 would have a capital cost of $27.8 million and result in an annual loss of 12,000 MW-hrs of electricity, whereas the December 2001 USGenNE 316(a) and (b) Demonstration estimated the capital costs for this option to be $48 million with lost annual generation of 25,000 MW-hrs.

[204] Actually, Abt uncovered two calculation errors in the permittee's Dynamic Cost Analysis. One error incorrectly reduced costs, but this reduction was more than offset by the second error, which incorrectly increased costs. Abt's analysis corrected both errors. See Abt Report (April 5, 2002), pp. 39-40.

SAIC conducted an independent assessment of the capital costs of the unit-specific and multi-mode cooling tower-based options under consideration as BAT for reducing thermal discharges from BPS. To do this, it conducted two separate analyses. Each analysis is discussed below, and their respective results are presented in a table along with the permittee's numbers.

SAIC's first analysis generated independent capital cost estimates for each cooling tower-based BAT option by comparing the permittee's detailed cost spreadsheets with an independent source of construction cost data (the "Independent Line Item Analysis").[205] SAIC analyzed the capital cost estimates, , which were submitted in detailed cost spreadsheets included in Volume V of the December 2001 USGenNE 316(a) and (b) Demonstration, and discussed in Volume IV of the December 2001 submission. It then identified similar cost items in an independent data source, the RS Means Cost Works database for the third quarter 2001.

Because the Costs Works database is a construction cost estimating resource for general construction throughout the United States, many of the specific unit cost items in the permittee's spreadsheets could not be matched with similar cost items in Costs Works; however, for each item that could be matched, SAIC used the Cost Works value in its analysis. In other words, SAIC did not selectively use some matching items and disregard others; it used all matching items. Depending on the BAT option being considered, SAIC was able to match between 16% and 23% of the cost items in the permittee's spreadsheets with cost items in the Cost Works data. Some of the Cost Works items were lower in cost, while others were higher.

In addition, SAIC took advantage of the Cost Works database feature that allows the use of cost factors to reflect specific regions of the country. In developing its independent cost estimates, SAIC chose data that represented the highest union labor rates for Boston, which is the most costly region in Massachusetts. These adjusted costs take into consideration regional costs for materials and labor, including the effects of using unionized labor.

For each cooling tower-based BAT option, SAIC compared the matched independent estimate line item costs to the permittee's line item costs for each cooling tower-based BAT option. This comparison indicated overall that the independent, Cost Works-based capital cost estimates were significantly less than the permittee's capital cost estimates. The ratio of the total of independent estimate line item costs to the total of the corresponding permittee line item costs indicated the relative extent to which the independent estimates were less than the permittee's estimates for each option (and inversely, the extent to which the permittee's estimates appear to have overestimated capital costs). Assuming that the comparative relationship observed for the matched items is representative of all of the cost items, multiplying this ratio by the corresponding total of permittee costs for a particular cooling tower-based BAT option yields an independent estimate of capital costs that is significantly lower than the permittee's estimate of

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[205] See SAIC Report (March 15, 2002), pp. 9-12.

capital costs.

Although there is some uncertainty, EPA believes that this assumption is not unreasonable. As noted above, SAIC did not pick and choose among the matching cost items; all matching items were used. Moreover, as SAIC points out, most of the difference between the independent estimates and the permittee's estimates appear to be attributable to differences in labor rates and man hours for the matching line items. In most cases, the Cost Works labor rate and man hour estimates are much lower than the permittee's estimates and, as SAIC points out, these types of differences can be expected for other line items. Finally, as mentioned above, SAIC used the Cost Works data for the third quarter of 2001 and for the Boston area, the most expensive area for Massachusetts. Thus, EPA believes SAIC's approach is unbiased, reasonable and appropriately conservative.

In its second analysis, SAIC derived capital cost estimates for each cooling tower-based BAT option under consideration using the costing methodology that EPA employed for estimating facility-level costs in the development of the CWA § 316(b) regulations (which the Agency recently promulgated for new facilities and proposed for large existing power plants) (the "316(b) Rule-Based Analysis").[206] SAIC adjusted the results produced by the cost equations that EPA developed for new facilities; it did so by applying the relevant cost factors that EPA used to account for retrofitting technology to existing facilities, using salt water (which is more corrosive than fresh water and necessitates the use of more expensive materials and better drift control) as cooling water, and using fiberglass cooling towers (as proposed by the permittee) rather than redwood towers (which is the base case for the 316(b) Rule cost analysis).[207]

SAIC noted that the permittee estimated the capital costs of converting more than one generating unit to closed-cycle cooling by first estimating the cost of converting each individual unit and then adding all of these costs together. For example, the permittee calculated the cost of the Closed-Cycle Entire Station option simply by summing the costs of separately converting Units 1, 2, 3 and 4. According to SAIC, this approach likely overestimated costs because it did not take into account the "economy of scale" benefit that would result from converting more than one unit at a time to closed-cycle cooling. Therefore, in the 316(b) Rule-Based Analysis, SAIC followed the permittee's approach but made the appropriate adjustment for economy of scale. (As a result, for example, it estimated the total economy of scale benefit for the Closed-Cycle

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206 See id., pp. 13-15.

207 SAIC and Tetra Tech are working on the 316(b) rulemaking effort for EPA and thus are well-versed in the Agency's 316(b) costing approaches. The 316(b) Rule costing methodology and costing equations are described in detail in the Technical Development Document for the 316(b) New Facility Rule (EPA 2001). Id., p. 14. This document can be found on EPA's website at http://www.epa.gov/ost/316b/.

Entire Station option to be approximately 6%.) SAIC also noted that the permittee increased the capital cost of each option by 10% to account for "contingencies" (as well as by an additional 10% to account for "indeterminate costs"). According to SAIC, the permittee's contingency adjustment appears high because typical contingency allowances for heavy construction projects are more typically in the range of 4% to 7%. It concluded, however, that a 10% factor might not be unreasonable due to site-specific factors. Therefore, it used the permittee's 10% factor for both contingencies and indeterminate costs in its analysis.

In addition, because of the permittee's concern that the use of cooling towers at BPS would cause fog/ice hazards that would require generating unit shutdowns for the unit-specific closed-cycle cooling options, SAIC estimated costs for system modifications that would obviate any need for such generating unit shutdowns. First, it adjusted the permittee's capital cost estimates to reflect the installation of pumping and piping that would be necessary to allow unit-specific cooling towers to function in multi-mode fashion. In other words, it determined the capital cost of equipping the cooling towers so that they could be by-passed to allow the generating units to be run in once-through mode, thus eliminating any need for generating unit shutdowns. Second, SAIC determined the capital cost of outfitting the cooling towers with plume abatement technology (i.e., based on traditional wet/dry hybrid cooling), instead of with multi-mode capability.

As SAIC explains, the costing methodology used for the 316(b) Rule represents a conservative approach to estimating costs (i.e., it tends to err on the side of higher cost estimates). Although the methodology was developed for a national, industry-wide cost assessment and therefore could fail to account for site-specific factors at a given plant, such as BPS, SAIC and EPA believe that the results of the 316(b) Rule-Based analysis are reasonable and conservative for BPS because SAIC's more site-specific Independent Line Item Analysis generated even lower capital cost estimates for retrofitting each of the BAT options under consideration.[208]

The capital cost estimates computed by the permittee, the EPA/SAIC Independent Line Item Analysis, and the EPA/SAIC 316(b) Rule-Based Analysis are presented in the table below.

Table 4.4-1: Capital Cost Estimates

[208] Id., p. 14. For comparison purposes, the 316(b) Rule-based cost estimates for retrofitting such towers with plume abatement technology indicate that the addition of plume abatement technology would roughly double these independent cost estimates, yielding costs that are within roughly 18% to 33% above the permittee's cost estimates. Id.

Technology Option	Permittee's Cost Estimates	EPA/SAIC Independent Line Item Analysis Cost Estimates	EPA/SAIC 316(b) Rule-Based Analysis Cost Estimates
"Enhanced Multi-Mode"*	$57.4 million	$18.8 million	$29.3 million
Closed-Cycle Unit 3*	$56.4 million	$19.8 million	$27.0 million
Closed-Cycle Unit 3* (with Multi-Mode)	X	X	$31.3 million
Closed-Cycle Unit 3* (with wet/dry for Plume Abatement)	X	X	$68.3 million
Closed-Cycle Units 1 or 2 & 3*	X	X	$50.8 million
Closed-Cycle Entire Station*	$176.7 million	$63.9 million	$80.7 million
Closed-Cycle Entire Station* (with Multi-Mode)	X	X	$93.8 million
Closed-Cycle Entire Station* (with wet/dry for Plume Abatement)	X	X	$202.3 million

* Assumes retrofitting to the existing facility, use of fiberglass towers and equipped for use with salt water.

"X" indicates that no value was calculated for that cell of the Table.

In order to be more conservative in our economic achievability analysis, EPA chose to proceed using the capital cost estimate values derived from SAIC's 316(b) Rule-Based Analysis (i.e., the far right-hand column of Table 4.4-1) for the unit-specific and multi-mode cooling tower options under consideration as BAT for reducing thermal discharges from BPS. Therefore, EPA instructed Abt to use these values in its evaluation of the "financial aspects" of the costs of these BAT options.

ii. Annual Auxiliary Power Costs

SAIC independently estimated annual auxiliary power costs (principally to run pumps and fans necessary for the cooling tower systems) as part of its analysis of annual O&M expenses for the various cooling tower-based BAT options for BPS.

It determined likely hours of operation and capacity for the plant's generating units based on various data from the permittee. It also evaluated fan and pump power needs based on values from technical analyses supporting EPA's 316(b) rulemaking, noting that the resulting figures could be "something of an overestimate" because in practice, a system likely would turn off fans for some percentage of its cooling tower cells, or reduce their speed, if possible, during cold weather. There were certain inconsistencies in the auxiliary power figures provided in various submissions by the permittee, which SAIC and EPA agreed to resolve by using the figures from the permittee's Dynamic Cost Analysis, which were the permittee's most recent figures. The auxiliary power consumption penalty estimate that SAIC derived by this approach was somewhat less than that predicted by the permittee for the Enhanced Multi-Mode option, but was higher than that predicted by the permittee for the unit-specific closed-cycle options. As a result, SAIC concluded that the permittee's auxiliary power estimates were reasonable and could be used in EPA's independent analysis.[209]

SAIC also estimated overall annual O&M costs, including annual auxiliary power costs, using the cost equations that EPA used to estimate O&M costs on a national basis for the 316(b) Rule. The independent O&M cost estimates that SAIC developed using the 316(b) Rule cost equations include material, labor and equipment necessary to keep the units operational (i.e., preventive maintenance, overhaul maintenance and auxiliary power requirements, but not energy efficiency penalties due to the effects of cooling water temperature on condenser and turbine performance); they have been verified with field data and are considered to be conservative.

To compare these 316(b) Rule-based cost estimates with the permittee's estimates, SAIC had to subtract estimated energy efficiency values that the permittee had combined with its estimated auxiliary power and O&M values. Under this 316(b) Rule-based approach, SAIC's overall annual O&M cost estimates, including auxiliary power cost estimates, were slightly less for the Enhanced Multi-Mode option and significantly higher for the unit-specific closed-cycle options. On the basis of this analysis, SAIC concluded that the permittee's annual O&M and auxiliary power cost estimates were reasonable and could be used in EPA's independent analysis.[210]

EPA agreed with SAIC that the permittee's cost estimates for annual O&M and auxiliary power

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[209] See id., pp. 16-20.

[210] See id., pp. 23-24 and Table 12.

needs are not unreasonable, and directed Abt to use the permittee's cost estimate values in its economic analysis. These values are presented in the following table:

Table 4.4-2: Permittee's Annual Maintenance and Auxiliary Power Costs

Technology Option	Maintenance Expense	Auxiliary Power Expense*
Enhanced Multi-Mode	$240,000/year	$2,542,610/year
Closed-Cycle Unit 3	$155,000/year	$1,923,005/year
Closed-Cycle Entire Station	$500,000/year	$5,632,550/year

* Figures derived from Table 12 in SAIC Report (March 15, 2002).

iii. Annual Costs from Energy Efficiency Penalties

Retrofitting cooling towers to an existing power plant will result in a marginal loss of electrical generation efficiency. This lost generation has a cost, and the permittee included this cost in its assessment of the costs of the various cooling tower options. SAIC independently assessed the cost that the permittee would incur in energy efficiency penalties.

On the basis of its review, SAIC concluded that the permittee has significantly overestimated the efficiency losses likely to result from installing cooling towers at BPS. SAIC conducted its analysis by applying the method that EPA to calculate cooling tower efficiency losses for the Boston area for the recently promulgated CWA § 316(b) regulations for new facilities. SAIC then made the following adjustments to tailor the analysis to the particular circumstances of BPS: (1) it used monthly average intake temperatures for the Taunton River for Units 1, 2 and 3, and for the Lee River for Unit 4; (2) it used time-weighted wet bulb temperatures for the 9:00 am to 4:00 pm time period from Providence/T.F. Green Airport historical weather data (the permittee has used T.F. Green weather data for certain of its analyses); and (3) for Unit 4, it made adjustments to reflect eight months of piggyback operations as currently practiced under MOA II. Using wet bulb temperatures from the hours of 9:00 am to 4:00 pm, rather than an average over a full 24-hour day, will tend to produce a higher efficiency penalty (i.e., be more conservative economically). In addition, SAIC based its calculations on a design approach of 10° F, rather than the 8° F used in the permittee's design, which will also tend to produce slightly higher efficiency penalty estimates. SAIC carried out calculations for both the 100% and 67% load cases, and then applied the results to the various BAT options based on the plant operating data presented earlier in its report (based on information obtained from the permittee).[211]

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[211] See id., pp. 20-24.

The results of SAIC's analysis, along with the permittee's values, are presented in the tables below.

Table 4.4-3: Wet Tower Annual Efficiency Losses

	Units 1, 2 and 3	Unit 4 (Piggyback)
100% Load	0.29%	0.09%
67% Load	0.75%	0.18%

Table 4.4-4: Annual Efficiency Penalty Estimates by Permittee and SAIC/EPA

Technology Option	Permittee Efficiency Penalty Estimate (MW-Hrs/year)	SAIC/EPA Independent Efficiency Penalty Estimate (MW-Hrs/year)	Percent Difference in Permittee and SAIC/EPA MW-Hr/year Estimates	SAIC/EPA Independent Efficiency Penalty Estimate Converted to $/year*
Enhanced Multi-Mode	25,278	10,673	- 58%	$373,555
Closed-Cycle Unit 3	64,108	16,629	-74%	$582,015
Closed-Cycle Entire Station	124,715	31,779	-75%	$1,112,265

* Figures derived for illustrative purposes only by EPA using SAIC efficiency penalty estimate and the permittee figure of $35.00 per MW-Hr. The analysis conducted by Abt for EPA estimates more specifically what the actual cost of the efficiency penalty is likely to be over time taking into account the changes in cost of generation and price received over time.

It should be remembered that BPS is expected to experience certain annual economic *gains* as a result of being able to generate *more* electricity during the peak demand hot weather periods during the summer. Depending on the BAT option being analyzed and the conclusions regarding certain other considerations, these gains are likely to either substantially offset, or more than offset, the auxiliary power and efficiency losses presented above. The issue of increased electrical generation allowed by cooling towers during hot weather periods is discussed further below.

iv. Costs from Generating Unit Construction Outages

The permittee has indicated that it believes that disconnection of the existing once-through cooling system and construction and connection of any one of the cooling tower-based options under consideration will necessitate certain generating unit outages. The permittee has agreed with EPA that these outages should be scheduled to coincide with regular annual maintenance outages as much as possible, but the permittee has also concluded that generating unit outages extending beyond the duration of annual maintenance outages will be necessary for the unit-specific cooling tower options (though not for the Enhanced Multi-Mode option). As a result, the permittee has added a cost for this one-time loss of electrical generation from construction outages to the overall cost of the unit-specific options.

Specifically, the permittee determined that an eight-month outage would be required for installing unit-specific closed-cycle cooling towers for Units 1, 2 and 3, and a three-month outage would be required for such a tower for installing Unit 4. These outages would run consecutively (i.e., back-to-back) for unit-specific cooling tower options for multiple units. In other words, downtime for converting the entire station to closed-cycle cooling would entail 27 unit-months.[212] Since these outages would run concurrently with the one-month annual maintenance outage for each unit, the cost of these outages in the permittee's Dynamic Cost Analysis are based on seven months of outages for Units 1, 2 and 3; no cost was attributed to the outage for Unit 4 because it is not typically on-line anyway.

SAIC evaluated the permittee's construction outage estimates and, on the basis of a conservative analysis, concluded that they appear to be excessive. SAIC determined that the principal reason for the relatively lengthy construction outages estimated by the permittee is the permittee's "decision to install an entirely new set of pumping stations for the recirculation pumps for Units 1, 2 and 3 in a manner that interferes with the current once-through operation." According to SAIC, "[t]his decision is based in part on the conclusion that the current pumps, piping and condenser may not be capable of handling the additional hydraulic pressure that would occur with the system if the condenser outlet were to be simply re-routed to the top of the new cooling

[212] See December 2001 USGenNE 316(a) and (b) Demonstration, Vol. IV, App. H, p. 3.3-29.

towers."[213]

In evaluating the permittee's approach, SAIC accepted the permittee's concerns about piping and condenser pressure as valid. In addition, it reviewed four case studies involving large power plants that converted from once-through cooling to cooling with closed-cycle mechanical draft cooling towers (one plant uses the towers in a helper mode).[214] The conversions in these case studies were undertaken with either no outages or far shorter outages than those estimated by the permittee, such as the 27 unit-months of outage that the permittee estimates for the Closed-Cycle Entire Station option. As SAIC explained, these other plants have "mostly been able to incorporate the existing pumps and pump stations, the existing condensers and much of the existing piping into the closed cycle systems." All but one of the four case study facilities were able to retain the existing once-through cooling water pumps and pumphouses and incorporate them into the wet cooling tower recirculation system, while the remaining facility kept the downtime "brief by installing a separate new pumphouse and piping in a manner that did not interfere with the existing system while under construction." As a result, this facility only required downtime to "disconnect the existing once-through cooling water pipes and reconnect the new cooling water system pipes." SAIC concluded that it is likely that either approach would be feasible for Units 1, 2 and 3.[215]

Nevertheless, SAIC took a conservative approach and assumed that Unit 1, 2 and 3's current once-through pumps would require replacement. Even still, it concluded that unit outage time could be shortened by retaining the existing pumphouse, replacing the existing pumps and then connecting the discharge pipe to the cooling towers. SAIC explained that:

> [a]s with USGenNE's proposed engineering design, water would flow by gravity through the condensers but would then be piped back to the intake wet well of the existing intake pumping station. Such a pump and pipe configuration would require the closing off of the individual intake bays for each unit, the replacement of the intake pumps, installation of the cooling water return piping from the condenser, replacement of electrical and control equipment, and tie-in of the new pump outlet pipe to the cooling tower. Without more detailed information regarding the intake structure configuration, it cannot be determined what other modification to the intakes might be necessary. However, the savings in construction costs for replacing the pumphouse should more than offset any

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213 SAIC Report (March 15, 2002), p. 25.

214 See id., Attachment A.

215 Id., p. 26.

modification costs. Certainly, the case study facilities came to that conclusion.[216]

To account for the constraints of working within the existing pumphouses, SAIC added back in two weeks of construction time. Ultimately, it concluded that the construction outage necessary for the installation of cooling-tower based technologies at BPS could conservatively be reduced to four months. Indeed, SAIC felt that it might be possible to reduce the outages for Units 1, 2 and 3 each to the three-month figure that the permittee estimated for Unit 4, but due to uncertainties about possible intake differences between the Unit 4 intake and the intake for Units 1, 2 and 3, it retained the four-month estimate for each unit. SAIC prepared a detailed construction-related unit downtime estimate for Unit 1 specifically, but concluded that the same approach and outage reductions could be achieved for Units 2 and 3 as well.[217]

Table 4.4-5: Permittee and Independent Construction Outage Estimates

Technology Option	Permittee Construction Outage Estimate (total unit-months)	Permittee Construction Outage Estimate (unit-months likely to cause generation losses in excess of normal maintenance outage)	EPA/SAIC Construction Outage Estimate (total unit-months)	EPA/SAIC Construction Outage Estimate (unit-months likely to cause generation losses in excess of normal maintenance outage)
Enhanced Multi-Mode	5.5 (broken into different periods for individual units)	0	5.5 (broken into different periods for individual units)	0

216 Id., p. 27.

217 See id., pp. 28-29.

Technology Option	Permittee Construction Outage Estimate (total unit-months)	Permittee Construction Outage Estimate (unit-months likely to cause generation losses in excess of normal maintenance outage)	EPA/SAIC Construction Outage Estimate (total unit-months)	EPA/SAIC Construction Outage Estimate (unit-months likely to cause generation losses in excess of normal maintenance outage)
Closed-Cycle Unit 3	8 (for Unit 3)	7 (for Unit 3)	4 (for Unit 3)	3 (for Unit 3)
Closed-Cycle Entire Station	27 (made up of separate 8-month periods for Units 1, 2 & 3, and 3 months for Unit 4)	21 (made up of separate 7-month periods for Units 1, 2 & 3)	15 (made up of separate 4-month periods for Units 1, 2 & 3, and 3 months for Unit 4)	9 (made up of separate 3-month periods for Units 1, 2 & 3)

On the basis of the SAIC analysis, supported by the case studies, EPA believes the generating unit outage period of four months (i.e., three months in excess of the one-month annual maintenance outage) for Units 1, 2 and 3 are reasonable and conservative, and it directed that these figures be used in Abt's economic analysis.

v. Period for Constructing the Closed-Cycle Entire Station Option

The permittee estimated that it would take a total of 47 months to construct the Closed-Cycle Entire Station option. Assessing this proposed construction period in light of the above-described reduced estimates for constructing the individual unit-specific cooling tower systems, SAIC concluded that the Closed-Cycle Entire Station construction period could be shortened from the permittee's estimated 47 months to an estimated 39 months. It could not reasonably be reduced by the full amount of the reduction for each individual unit because of the necessary sequencing of various tasks for bringing each unit on-line. EPA instructed Abt to use this 39-month construction period estimate in its economic analysis.[218]

4.4.3b "Financial Aspects"

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[218] See id., p. 29.

Abt conducted a multi-faceted independent analysis of the cost of the various unit-specific and multi-mode cooling tower-based options to the permittee over time. This analysis takes into account capital costs, the cost of one-time construction outages, various annual costs (e.g., O&M costs, auxiliary power cost penalties, reduced generation efficiency penalties, alleged vapor plume abatement outage penalties), and taxes. It presents the overall accumulated costs over the specified time period both as a *total* present value, after-tax cash flow total cost and as an *equivalent annual* present value, after-tax cash flow cost.

There are numerous complexities involved in undertaking this type of financial/economic analysis. For example, determining the cost of the reduction in electrical generation that would be associated with each cooling tower-based option (as the result of, for example, construction outages or auxiliary power penalties) requires estimation of the additional profits that the permittee could have made over time if generation had not been reduced. This in turn requires estimation of the costs of producing the electricity over time, and subtraction of those estimated production costs from the estimated prices at which the permittee could have sold the electricity over time. Despite these complexities, the permittee, EPA and the MA DEP all agreed that this type of analysis was the most appropriate way to assess the cost to the permittee of the various options. (All the parties agreed this approach was a more accurate way of assessing costs than the "static cost analysis" that the permittee initially presented to the regulatory agencies in June 2001.) Thus, the permittee also conducted this type of analysis in its "Dynamic Cost Analysis," which it submitted to EPA as part of the December 2001 USGenNE 316(a) and (b) Demonstration, Vol. III, App. G (Tab: Dynamic Cost Analysis). Abt's analysis and the permittee's Dynamic Cost Analysis undertake equivalent assessments, and their results can be meaningfully compared with each other.

The first step in Abt's analysis was essentially to re-create the Dynamic Cost Analysis financial assessment model. Abt did this to ensure that it correctly understood the permittee's analysis, to assess the validity of the permittee's approach, and to determine whether the permittee's results were accurate based on the model used and the inputs to it. As Abt stated, this represented a "due diligence" review.

Abt then went on to vary inputs to the financial assessment model as it deemed appropriate based on its independent expert opinion on financial/economic issues, and as directed by EPA on the basis of EPA's and SAIC's independent expert opinions on engineering issues. (An example of such a financial/economic issue is use of a discount rate different than that used by the permittee; an example of such an engineering issue is use of different capital costs than those used by the permittee.) For a number of factors, Abt analyzed a variety of alternative scenarios in order both to ensure that it considered issues from more than one perspective, and to discern the overall effect on the results of the choices made with respect to these factors. For example, as discussed below, Abt looked at overall costs over both a 20-year and a 30-year equipment operating life.

The financial/economic analysis conducted by Abt is quite complex, and it is explained in detail in the report attached hereto as App. C and incorporated herein by reference. EPA does not repeat the analysis in detail here. We do, however, present its key results and discuss the principal factors that went into it.

i. **Abt's Replication of the Permittee's Dynamic Cost Analysis Model**

In order to analyze the unit-specific and multi-mode cooling tower-based options under consideration for BPS, Abt developed an analytic framework that essentially replicates the permittee's analysis. Apart from presentation differences, Abt's analytic framework differs materially from the permittee's framework only in including the ability to adjust the time period of analysis and recognize explicitly the estimated schedule requirements for installation of capital equipment and subsequent operating periods for technology equipment. By constructing this analytic framework and validating the permittee's analysis, Abt was able to replicate the analyses presented in the Dynamic Cost Analysis in virtually all respects, including the electricity price and input fuel cost schedules used in the permittee's analysis.

However, while Abt was able to replicate the *growth rates* of the electricity price and input fuel cost schedules going forward in time, based on the electricity price and fuel cost forecasts developed by Resource Data International (RDI) and submitted to EPA by the permittee (including those that depend on a blending of on- and off-peak price schedules), Abt was not able to independently verify the first-year values of electricity prices and input fuel costs for these schedules. These first-year values are reported by the permittee to be the current (presumed 2001) values observed in operation of BPS. Accordingly, while the projections of future electricity prices and input fuel costs track the RDI projections in terms of change over time, the absolute numerical values in these schedules depend on the permittee's reported baseline values. Again, Abt was not able to independently validate these baseline values, which provide the "seed" for the future projection schedules. As a result, it used them in its analysis.

In addition, Abt's replication of the permittee's analysis revealed the following two calculation errors by the permittee that materially affect the results of the Dynamic Cost Analysis:[219]

> 1. *Improper referencing of certain spreadsheet cells in the calculations*. In the permittee's model for the Closed-Cycle Entire Station option, the spreadsheet row labeled "After-Tax Annual Cost" is improperly calculated. Specifically, the spreadsheet row titled "Tax Cost (Savings)" is added to the row labeled "Total Cost of Plume Abatement" instead of the proper row "Annual Cost" for the calculation of "After-Tax Annual Cost." As a result, total after-tax annual costs are *understated* in all years of the analysis, and the

[219] Abt Report (April 5, 2002), pp. 39-40.

subsequent calculations of present value and equivalent annual cost carry forward this error. When corrected, the total present value of cost for this option under the permittee's 15% discount rate increases by $15.7 million. The permittee does not make this error in its analysis of the Enhanced Multi-Mode and Closed-Cycle Unit 3 options.

2. *Failure to account for the tax treatment of the construction outage income loss.* In its analysis of the Closed-Cycle Unit 3 and Closed-Cycle Entire Station options, the permittee does not account for the tax treatment of the income loss during construction outages: the construction outage causes a reduction in income, which in turn reduces the permittee's tax liability during that operating period. This treatment is inconsistent with the permittee's proper recognition of the tax treatment of other revenue and cost effects from installation and operation of technology equipment. As a result, the permittee's analysis overstates the cost of the Closed-Cycle Unit 3 and Closed-Cycle Entire Station options by $21.3 million and $39.1 million, respectively. This error is irrelevant to the permittee's analysis of the Enhanced Multi-Mode option, because the permittee anticipates no construction outage income loss from this option.

The net effect of these errors is that within its own framework of calculations and cost estimates, the permittee's analysis overstates the total present value of cost. In the permittee's 15% discount rate case, it overstates the total present value of cost by $21.3 million for the Closed-Cycle Unit 3 option and by $23.4 million for the Closed-Cycle Entire Station option. These errors are material in the permittee's analysis, representing approximately 17% of the permittee's total present value of cost for the Closed-Cycle Unit 3 option and approximately 15 % of the permittee's total present value of cost for the Closed-Cycle Entire Station option.

In response to these two errors, when Abt presented the permittee's cost estimates for the purpose of comparing them with its independent cost estimates, it corrected the permittee's numbers to fix the two errors. As a result, Abt's *re-estimates* of the permittee's cost and cost effectiveness values for the Closed-Cycle Unit 3 and Closed-Cycle Entire Station options are somewhat lower than the values actually reported by the permittee in the Dynamic Cost Analysis.

Finally, Abt's calculations yielded other small differences from the permittee's Dynamic Cost Analysis values and interpreted them to arise from rounding. Abt indicated that these differences amounted to no more than a few thousand dollars in any given instance, and it concluded that the differences were inconsequential in the aggregate.

ii. Elements of Abt's Independent Financial/Economic Analysis

Some of the key aspects of Abt's independent financial/economic analysis are discussed below.

Capital Costs. Abt used the capital costs from SAIC's independent CWA § 316(b) Rule costing methodology-based analysis. As explained above, EPA directed Abt to use these figures rather than the figures from SAIC's Independent Line Item Analysis, because the former were higher and would therefore result in a more conservative analysis.

Duration of Construction Outage. As discussed above, Abt used the construction outage figures calculated by SAIC.

Date for Commencement of Construction; Timing of Construction Outage. The time when one assumes construction would begin (and end) and the timing of the construction outages both impact the results of the financial/economic analysis. The permittee's Dynamic Cost Analysis assumed that construction began and ended in 2001 and valued the construction outage based on the "spark spread price" from 2001. Given that it was already early 2002 when Abt was working on its analysis, it is indisputable that construction could not begin and end in 2001. Therefore, EPA and Abt agreed to use mid-2002 as the time for construction to start. In addition, Abt assumed that construction outages would occur at the end of the construction period and, therefore, valued the outages based on the spark spread price estimated for those times.

Construction Duration. As discussed above, the timing of construction and any outages affects the financial/economic analysis. Abt used the construction duration calculated by SAIC for the Closed-Cycle Unit 3 option and the Closed-Cycle Entire Station option, but consistent with SAIC's recommendation, used the permittee's construction duration estimate for the Enhanced Multi-Mode option.

O&M. Consistent with SAIC's recommendation, EPA directed Abt to use the annual O&M expenses developed by the permittee.

Auxiliary power Cost Penalties. Consistent with SAIC's recommendation, EPA directed Abt to use the annual auxiliary power penalties (in MWHrs) developed by the permittee. Like the permittee, Abt valued these penalties on the basis of lost revenue.

Energy Efficiency Cost Penalties. As discussed above, EPA directed Abt to use the annual energy efficiency penalty figures (in MWHrs) developed by SAIC. Like the permittee, Abt valued these penalties on the basis of lost revenue.

Economic Gain from "Avoided Load Loss." As discussed above, the permittee acknowledges that the cooling tower-based options would offer an economic benefit because they would enable greater electrical generation during certain peak demand (and therefore peak sales price) hot weather periods during which the permittee currently must curtail (or cap) generation to avoid violating the 95° F maximum temperature discharge limit presently in its NPDES permit. Abt has referred to this benefit as the "avoided load loss." This benefit would occur because summer intake water temperatures can get high enough that heat added to the water by the power plant can push the discharge temperature over 95° F, but cooling towers could minimize this problem by rejecting heat to the atmosphere rather than back to Mount Hope Bay in the cooling water.

In its calculations, Abt used the permittee's estimate of the extent of avoided load loss events, which was based in part on permittee historical data from 1989 to 1999. In light of data (discussed elsewhere in this document) indicating an upward, long-term trend in the temperature of the waters of Mount Hope Bay (and Narragansett Bay), EPA notes that using the 1989-1999 data is likely to result in a relatively conservative estimate of avoided load loss events going forward. Further, Abt noted that if the permittee had used data that included the very warm summer of 2001, then its estimated value of the avoided load loss also would have been higher. While acknowledging the avoided load loss benefit, the permittee determined that if it discharged more heat during peak periods, then in order to remain within its overall permit limits it would have to offset the increases by reducing generation during off-peak (and therefore lower sales price) periods. Abt followed the permittee's approach to handling and estimating the value of this offset.

In addition, the permittee estimated that the Enhanced Multi-Mode and Closed-Cycle Entire Station options would be able to capture all (100%) of the potential avoided load loss, but that the Closed-Cycle Unit 3 option would only be able to capture part (48.6%) of the potential benefit. The permittee did not clearly explain how it came up with this 48.6% figure, and Abt was unable to independently verify it. With no clear basis for an alternative figure, EPA and Abt decided to take the conservative approach of using the permittee's figures.

Placing a dollar value on avoided load losses requires calculating the profits that would have been lost to generating load curtailment. This is done by determining baseline figures for the fuel cost for producing the electricity and for the price at which that electricity could have been sold. Working from these baseline figures, future changes in electricity prices and fuel costs must then be estimated to determine the future value of the net loss in operating income to the permittee from the predicted curtailment in generation that would have occurred in the absence of a particular cooling tower option.

In reviewing both the permittee's July 2001 "static economic analysis" and the Dynamic Cost Analysis that the permittee submitted to EPA in December 2001, Abt found that the permittee used different baseline spark spread price schedules in the two analyses. In its July 2001 analysis, the permittee used a schedule based on wholesale electricity prices from the summer of 1999. In the Dynamic Cost Analysis, however, it used a baseline price schedule reportedly based on price data from 1999 and 2000, but not from the very warm summer of 2001. The schedule in the Dynamic Cost Analysis substantially reduced the price schedule from the July 2001 range of $20.00 to $400.00 per MWHr to a new range of $35.66 to $78.13 per MWHr. Abt found that this substantially reduces the value of the avoided load loss benefit (e.g., a 28% reduction in the baseline year). Abt also found that the permittee did not provide any data supporting a cap on the spark spread price at $78.13 per MWHr. Therefore, Abt conducted an independent analysis to judge the reasonableness of the spark spread price schedule by reviewing energy clearing price (ECP) data for the summers of 1999, 2000 and 2001 from Independent System Operator-New England (ISO). Abt found that values ranged as high as $1000 per MWHr, with a maximum average for a given temperature of $409.06 per MWHr. Therefore, Abt concluded that it could not justify the $78.13 cap on the spark spread price schedule used in the Dynamic Cost Analysis, and that the baseline schedule from the permittee's July 2001 static analysis appeared to be more reasonable. As a result, in assessing the avoided load loss benefit for the independent financial/economic analysis, Abt used the baseline spark spread price schedule from the permittee's July 2001 static analysis.

Building off the baseline spark spread price schedule, the permittee's Dynamic Cost Analysis estimated the operating effects over time of the avoided load loss benefit based on a forecast of year-to-year changes in on-peak wholesale electricity prices, fuel costs, and spark spread prices developed by RDI. Abt concluded that this approach was reasonable. Therefore, Abt used the "implied growth rates" from the Dynamic Cost Analysis to project future spark spread price values from the permittee's July 2001 static cost analysis baseline schedule.

Unit Outages to Abate Alleged Hazard from Cooling Tower Water Vapor Plumes. As discussed elsewhere in this document, the permittee has concluded that generating unit outages will be necessary for the unit-specific cooling tower options in order to abate potential fog and/or ice hazards from cooling tower water vapor plumes. Although a very small number of hours of potential cooling tower-induced fog or ice were predicted by its model, the permittee's analysis concluded that hundreds of hours of outage would be needed to prevent these few hours of predicted tower-induced fog and/or ice. The cost of these outages is a significant element in the permittee's economic analysis. The permittee estimates that no such outages will be needed for the Enhanced Multi-Mode option because the cooling towers can be bypassed.

EPA has explained its skepticism about the permittee's conclusions elsewhere in this document. Given this skepticism, EPA asked Abt to assess the financial ramifications of several different scenarios. First, we asked Abt to evaluate the matter assuming no plume abatement unit outages. For this scenario, however, we instructed Abt to use the SAIC capital cost estimates that include an upward adjustment for the cost of adding piping and pumping to enable the unit-specific option to be operated in a multi-mode fashion so that the cooling towers could be bypassed if necessary. Abt's analysis showed that these increased capital costs would be more than offset by the economic benefit of avoiding the permittee's predicted unit outages. Second, we asked Abt to evaluate costs assuming that 100% of the permittee's predicted outages would, in fact, be necessary. Third, we asked Abt to evaluate costs assuming that 50% of the permittee's predicted outages would be necessary. For the latter two scenarios, Abt used SAIC's estimated capital costs for the unit-specific options without the cost adjustment for modifications to operate in a multi-mode fashion. In order to determine the cost to the company of the outages, Abt followed the permittee's approach, including the use of RDI data to determine the future revenue losses due to the outages.

Life of Capital Equipment; Time Horizon for Economic Analysis. The permittee assumed a 20-year life for the capital equipment. It also assumed that construction began and ended in 2001, and did its present value calculations at 2001.

EPA, SAIC and Abt concluded that 20 years might underestimate the reasonable life of the capital equipment, including the likely remaining life of the major components of the entire BPS, and concluded that 30 years might be a more reasonable figure. Indeed, for the CWA § 316(b) rulemaking, EPA has assumed a 30-year life for this equipment. Therefore, Abt did its analyses for two scenarios: one assuming a 20-year life and one assuming a 30-year life. As discussed above, Abt assumed that construction began in mid-2002, determined the first year of operation based on the particular option's construction schedule, and did its present value calculations back to mid-2002.

Depreciation. The permittee's Dynamic Cost Analysis used a 20-year straight-line depreciation schedule, with no depreciation recorded in the first year of operation (i.e., only 19 years of depreciation were included). Abt concluded that it was not reasonable to omit the first year of depreciation and, as a result, recorded a full year of depreciation in the first operating year. Abt noted that its approach yielded a lesser depreciation tax benefit than that which would have accrued if a Modified Accelerated Cost Recovery Schedule (MACRS) had been used instead of the 20-year straight-line approach. It also noted that a MACRS approach probably would be appropriate in this case. EPA agrees that Abt's decision to use a 20-year straight-line schedule, but to include depreciation in the first operating year, is a reasonable and conservative approach.

Discount Rate. The permittee did not want to reveal its internal company discount rate/cost of capital, which it regards as highly confidential business information. As a result, the permittee used a range of discount rates that it stated would encompass the rate it would use in its assessment of investment opportunities. The permittee then conducted its Dynamic Cost Analysis for two scenarios: one using a discount rate of 15% and one using a discount rate of 20%.

In order to test the reasonableness of the permittee's figures, Abt undertook a cost-of-capital analysis for six comparable merchant power producers. From this analysis, Abt estimated a market capitalization-weighted cost-of-capital of 11.8%. Abt then used this figure as the discount rate for its analyses.

iii. Comparison of Abt's Independent Financial/Economic Analysis and the Permittee's Dynamic Cost Analysis

Abt's financial/economic analysis yielded costs that were substantially lower than the costs indicated by the permittee's analysis. A number of factors played into this result, but the most important was the difference in capital cost inputs, followed (in no particular order) by efficiency penalty inputs, treatment of the water vapor plume abatement issue, construction outage inputs and avoided load loss inputs. It should be noted that under Abt's 30-year cost assessment, the Enhanced Multi-Mode option would actually earn money for the permittee due to the combination of the avoided load loss benefit over time and the other factors previously mentioned. As described above, Abt also evaluated a number of different scenarios by varying certain elements in the analysis. The several tables below present a comparison of some of the key conclusions of Abt's analysis with those of the permittee's analysis.

Table 4.4-6: Comparison of Selected Permittee and EPA/Abt Cost Scenarios

Technology Option	Permittee 15% Discount Rate Figures (with calculation errors corrected by Abt) (over 20 years)[1]	EPA/Abt Figures (using 11.8 Discount Rate and other independent values) (over 20 years)	EPA/Abt Figures (using 11.8 Discount Rate and other independent values) (over 30 years)
Enhanced Multi-Mode			
Total After-Tax Cash Flow Cost, Present Value:	$38.233 Million	$1.077 Million	- $909 Thousand*
Annual Equivalent Cost:	$6.108 Million	$142 Thousand	- $111 Thousand*

Technology Option	Permittee 15% Discount Rate Figures (with calculation errors corrected by Abt) (over 20 years)[1]	EPA/Abt Figures (using 11.8 Discount Rate and other independent values) (over 20 years)	EPA/Abt Figures (using 11.8 Discount Rate and other independent values) (over 30 years)
Closed-Cycle Unit 3			
0% plume abatement[2]			
Total After-Tax Cash Flow Cost, Present Value:	Not Calculated	$23.574 Million	$23.031 Million
Annual Equivalent Cost:	Not Calculated	$3.117 Million	$2.817 Million
50% plume abatement[3]			
Total After-Tax Cash Flow Cost, Present Value:	Not Calculated	$29.710 Million	$30.337 Million
Annual Equivalent Cost:	Not Calculated	$3.928 Million	$3.710 Million
100% plume abatement[4]			
Total After-Tax Cash Flow Cost, Present Value:	$104.949 Million	$38.861 Million	$40.658 Million
Annual Equivalent Cost:	$16.767 Million	$5.138 Million	$4.973 Million

Technology Option	Permittee 15% Discount Rate Figures (with calculation errors corrected by Abt) (over 20 years)[1]	EPA/Abt Figures (using 11.8 Discount Rate and other independent values) (over 20 years)	EPA/Abt Figures (using 11.8 Discount Rate and other independent values) (over 30 years)
Closed-Cycle Entire Station Units			
0% plume abatement[2]			
Total After-Tax Cash Flow Cost, Present Value:	Not Calculated	$68.385 Million	$67.975 Million
Annual Equivalent Cost:	Not Calculated	$9.041 Million	$8.314 Million
50% plume abatement[3]			
Total After-Tax Cash Flow Cost, Present Value:	Not Calculated	$71.685 Million	$72.747 Million
Annual Equivalent Cost:	Not Calculated	$9.477 Million	$8.898 Million
100% plume abatement[4]			
Total After-Tax Cash Flow Cost, Present Value:	$254.485 Million	$83.269 Million	$85.803 Million
Annual Equivalent Cost:	$40.657 Million	$11.009 Million	$10.494 Million

* Negative numbers indicate the permittee is gaining the indicated amount of money.

[1] The permittee figures for Closed-Cycle Unit 3 and Closed-Cycle Entire Station Units reflect the permittee's capital costs and its assumptions for generating unit outages for water vapor plume abatement.

[2] The Abt/EPA "0% plume abatement" figures reflect no generating unit outages for plume abatement, but do reflect the SAIC-estimated capital costs that were increased to reflect piping and pumping costs to allow the cooling towers to function in multi-mode fashion so that they could be bypassed to avoid generating unit outages for plume abatement.

[3] The Abt/EPA "50% plume abatement" numbers reflect calculations including 50% of the plume abatement effect predicted by the permittee. However, these figures also reflect SAIC's capital cost estimates without the upward adjustment to equip the cooling towers for potential multi-mode functioning.

[4] The Abt/EPA "100% plume abatement" numbers reflect calculations including 100% of the plume abatement effect predicted by the permittee. However, these figures also reflect SAIC's capital cost estimates without the upward adjustment to equip the cooling towers for potential multi-mode functioning.

Table 4.4-7: Permittee Total & Annual Equivalent Costs (with & without Calculation Errors Corrected by Abt)

Technology Option	Permittee Figures (15% Discount Rate/over 20 years) w/o Calculation Correction	Permittee Figures (20% Discount Rate/over 20 years) w/o Calculation Correction	Abt-Replicated Permittee Figures w/ calculation Correction (15% Discount Rate/over 20 years)	Abt-Replicated Permittee Figures w/ calculation Correction (20% Discount Rate/over 20 years)
Enhanced Multi-Mode				
Total After-Tax Cash Flow Cost, Present Value:	$38,226,000	$41,981,000	$38,228,000	$41,983,000
Annual Equivalent Cost:	$6,107,000	$8,621,000	$6,107,000	$8,621,000
Closed-Cycle Unit 3				
Total After-Tax Cash Flow Cost, Present Value:	$126,289,000	$122,688,000	$104,964,000	$101,366,000
Annual Equivalent Cost:	$20,176,000	$25,195,000	$16,769,000	$20,816,000
Closed-Cycle Entire Station Units				
Total After-Tax Cash Flow Cost, Present Value:	$267,294,000	$268,717,000	$254,768,000	$250,638,000
Annual Equivalent Cost:	$42,703,000	$55,183,000	$40,702,000	$51,470,000

Table 4.4-8: Abt/EPA Cost Estimates Over 20- and 30-Year Periods

Technology Option (& Plume Abatement Assumption)	Abt/EPA Total After-Tax Cash Flow Cost, Present Value (20-Year Period)	Abt/EPA Annual Equivalent Cost (20-Year Period)	Abt/EPA Total After-Tax Cash Flow Cost, Present Value (30-Year Period)	Abt/EPA Annual Equivalent Cost (30-Year Period)
Enhanced Multi-Mode				
(No Plume Abatement)[2]	$1.077 Million	$142 Thousand	- $909 Thousand[1]	- $111 Thousand[1]
Closed-Cycle Unit 3				
0% Plume Abatement[3]	$23.574 Million	$3.117 Million	$23.031 Million	$2.817 Million
50% Plume Abatement[4]	$29.710 Million	$3.928 Million	$30.337 Million	$3.710 Million
100% Plume Abatement[5]	$38.861 Million	$5.138 Million	$40.658 Million	$4.973 Million
Closed-Cycle Entire Station				
0% Plume Abatement[3]	$68.385 Million	$9.041 Million	$67.975 Million	$8.314 Million
50% Plume Abatement[4]	$71.685 Million	$9.477 Million	$72.747 Million	$8.898 Million
100% Plume Abatement[5]	$83.269 Million	$11.009 Million	$85.803 Million	$10.494 Million

[1] Negative numbers indicate the permittee is gaining the indicated amount of money.

[2] The permittee has concluded no plume abatement generating outages are needed for the Enhanced Multi-Mode option. EPA/Abt adopted this assumption as well.

[3] The Abt/EPA "0% plume abatement" figures reflect <u>no</u> generating unit outages for plume abatement, but do reflect the SAIC-estimated capital costs that were increased to reflect piping and pumping costs to allow the cooling towers to function in multi-mode fashion so that they could be bypassed to avoid generating unit outages for plume abatement.

[4] The Abt/EPA "50% plume abatement" numbers reflect calculations including 50% of the plume abatement effect predicted by the permittee. However, these figures also reflect SAIC's capital cost estimates without the upward adjustment to equip the cooling towers for potential multi-mode functioning.

[5] The Abt/EPA "100% plume abatement" numbers reflect calculations including 100% of the plume abatement effect predicted by the permittee. However, these figures also reflect SAIC's capital cost estimates without the upward adjustment to equip the cooling towers for potential multi-mode functioning.

Table 4.4-9: Detailed Permittee and EPA/Abt Costs for Enhanced Multi-Mode Option

Parameter	Permittee (15% Discount Rate) (w/ Calculation Errors Corrected by Abt) (20-Year Period)	EPA/Abt (using 11.8% Discount Rate and other Independent Elements) (20 Years)	EPA/Abt (using 11.8% Discount Rate and other Independent Elements) (30 Years)
Capital Costs	$57.406 Million	$24.054 Million	$24.054 Million
Construction Outage Cost	$0	$0	$0
Total Initial Cost, Net Depreciation Tax Benefit	$50.112 Million	$20.324 Million	$20.324 Million
Maintenance	$1.186 Million	$1.070 Million	$1.207 Million
Auxiliary power and Efficiency Penalties	$13.775 Million	$9.896 Million	$10.965 Million
Avoided Load Loss Benefit	- $26.840 Million[1]	- $30.212 Million[1]	- $33.405 Million[1]
Cost of Plume Abatement	$0	$0	$0
Total of Annual Expenses, After Tax	-$11.879 Million[1]	- $19.246 Million[1]	- $21.232 Million[1]
Present Value Total After-Tax Cash Flow	$38.233 Million	$1.077 Million	- $909 Thousand[1]
Equivalent Annual Cost	$6.108 Million	$142 Thousand	- $111 Thousand[1]

[1] Negative numbers indicate the permittee is gaining the indicated amount of money.

Table 4.4-10: Detailed Permittee and EPA/Abt Costs for Closed-Cycle Unit 3 Option

Parameter	Permittee (20 Years) 100% Plume*[1]	EPA/Abt (20 Years) 0% Plume*[2]	EPA/Abt (20 Years) 50% Plume*[2]	EPA/Abt (20 Years) 100% Plume*[2]	EPA/Abt (30 Years) 0% Plume*[2]	EPA/Abt (30 Years) 50% Plume*[2]	EPA/Abt (30 Years) 100% Plume*[2]
Capital Costs	$56.4 Million	$25.692 Million	$22.123 Million	$22.123 Million	$25.692 Million	$22.123 Million	$22.123 Million
Construction Outage Cost	$30.688 Million	$7.349 Million	$7.349 Million	$7.349 Million	$7.349 Million	$7.349 Million	$7.349 Million
Total Initial Cost, Net Depreciation	$79.921 Million	$29.057 Million	$26.042 Million	$26.042 Million	$29.057 Million	$26.042 Million	$26.042 Million
Maintenance	$0.766 Million	$0.691 Million	$0.691 Million	$0.691 Million	$0.780 Million	$0.780 Million	$0.780 Million
Aux. Energy & Efficiency Penalties	$16.747 Million	$8.501 Million	$8.501 Million	$8.501 Million	$9.419 Million	$9.419 Million	$9.419 Million
Avoided Load Loss Benefit	- $13.036 Million[3]	- $14.674 Million[3]	- $14.674 Million[3]	- $14.674 Million[3]	- $16.225 Million[3]	- $16.225 Million[3]	- $16.225 Million[3]
Cost of Plume Abatement	$20.566 Million	$0	$9.151 Million	$18.302 Million	$0	$10.321 Million	$20.642 Million
Total Annual Expenses, After Tax	$25.043 Million	- $5.482 Million[3]	$3.669 Million	$12.819 Million	- $6.026 Million[3]	$4.295 Million	$14.616 Million
Present Value Total After-Tax Cash Flow	$104.964 Million	$23.574 Million	$29.710 Million	$38.861 Million	$23.031 Million	$30.337 Million	$40.658 Million
Equivalent Annual Cost	$16.769 Million	$3.117 Million	$3.928 Million	$5.138 Million	$2.817 Million	$3.710 Million	$4.973 Million

* The permittee figures for the Closed-Cycle Unit 3 option reflect the permittee's capital cost estimates and predicted generating unit outages for water vapor plume abatement. Abt/EPA figures for the "0% Plume" case reflect no unit outages for plume abatement, but do reflect the SAIC estimates of capital costs that were increased to reflect piping and pumping to equip the cooling towers to function in multi-mode fashion so that they could be bypassed to avoid any plume abatement outage. Abt/EPA figures for the "50% Plume" and "100% Plume" reflect the stated percentage of the permittee's predicted plume abatement outages, but also reflect the SAIC capital cost estimates that were not adjusted for multi-mode capacity.

1 The permittee figures reflect its analysis using a 15% discount rate, with calculation errors corrected by Abt.

2 Abt/EPA figures reflect a discount rate of 11.8%, as explained above.

3 Negative numbers indicate the permittee is gaining the indicated amount of money.

Table 4.4-11: Detailed Permittee and EPA/Abt Costs for Closed-Cycle Entire Station Units Option

Parameter	**Permittee (20 Years) 100% Plume*[1]**	**EPA/Abt (20 Years) 0% Plume*[2]**	**EPA/Abt (20 Years) 50% Plume*[2]**	**EPA/Abt (20 Years) 100% Plume*[2]**	**EPA/Abt (30 Years) 0% Plume*[2]**	**EPA/Abt (30 Years) 50% Plume*[2]**	**EPA/Abt (30 Years) 100% Plume*[2]**
Capital Costs	$176.676 Million	$70.592 Million	$60.788 Million	$60.788 Million	$70.592 Million	$60.788 Million	$60.788 Million
Construction Outage Cost	$56.290 Million	$13.325 Million	$13.325 Million	$13.325 Million	$13.325 Million	$13.325 Million	$13.325 Million
Total Initial Cost, Net Depreciation	$210.517 Million	$72.971 Million	$64.686 Million	$64.686 Million	$72.971 Million	$64.686 Million	$64.686 Million
Maintenance	$2.347 Million	$1.945 Million	$1.945 Million	$1.945 Million	$2.195 Million	$2.195 Million	$2.195 Million
Aux. Energy & Efficiency Penalties	$40.182 Million	$20.805 Million	$20.805 Million	$20.805 Million	$23.055 Million	$23.055 Million	$23.055 Million
Avoided Load Loss Benefit	- $26.840 Million[3]	- $27.336 Million[3]	- $27.336 Million[3]	- $27.336 Million[3]	- $30.245 Million[3]	- $30.245 Million[3]	- $30.245 Million[3]
Cost of Plume Abatement	$28.278 Million	$0	$11.584 Million	$23.169 Million	$0	$13.056 Million	$26.112 Million
Total Annual Expenses, After Tax	$43.968 Million	- $4.586 Million[3]	$6.998 Million	$18.583 Million	- $4.995 Million[3]	$8.061 Million	$21.117 Million
Present Value Total After-Tax Cash Flow	$254.485 Million	$68.385 Million	$71.685 Million	$83.269 Million	$67.975 Million	$72.747 Million	$85.803 Million
Equivalent Annual Cost	$40.657 Million	$9.041 Million	$9.477 Million	$11.009 Million	$8.314 Million	$8.898 Million	$10.494 Million

* The permittee figures for the Closed-Cycle Unit 3 option reflect the permittee's capital cost estimates and predicted generating unit outages for water vapor plume abatement. Abt/EPA figures for the "0% Plume" case reflect no unit outages for plume abatement, but do reflect the SAIC estimates of capital costs that were increased to reflect piping and pumping to equip the cooling towers to function in multi-mode fashion so that they could be bypassed to avoid any plume abatement outage. Abt/EPA figures for the "50% Plume" and "100% Plume" reflect the stated percentage of the permittee's predicted plume abatement outages, but also reflect the SAIC capital cost estimates that were not adjusted for multi-mode capacity.

1 The permittee figures reflect its analysis using a 15% discount rate, with calculation errors corrected by Abt.

2 Abt/EPA figures reflect a discount rate of 11.8%, as explained above.

3 Negative numbers indicate the permittee is gaining the indicated amount of money.

4.5 Consideration of Other Remaining Factors Under CWA § 304

4.5.1 Non-Water Quality-Related Environmental Impacts (Including Energy Impacts)

There are several non-water quality-related environmental issues to consider with respect to a potential cooling tower retrofit at BPS. For example, shifting to closed-cycle cooling would result in a marginal decrease in the amount of electricity generated for sale by the plant due to the energy efficiency and auxiliary power penalties discussed in Section 4.4 above and Section 4.5.1e below. This marginal decrease in power generation could in turn contribute to marginal increases in air pollution if BPS were to try to offset the lost generation by burning more fuel to generate more electricity. In addition, according to the permittee, retrofitting all or some of the units at BPS with wet mechanical draft cooling towers could have adverse noise, visual/aesthetic and salt drift impacts. EPA does not believe that any of these issues presents a fatal flaw for a retrofit of mechanical draft wet cooling towers at BPS.

Each of the unit-specific and multi-mode wet cooling tower options raise the same issues concerning potential non-water quality environmental and energy impacts.[220] Therefore, this determination document discusses these issues together. Nonetheless, wherever important distinctions can be drawn between the options, these distinctions are identified and addressed. EPA notes that while as a general matter, the more cooling tower cells an option involves, the greater the magnitude of the potential impacts is, this does not necessarily mean that any such impacts are significant.

4.5.1a Air Pollutant Emissions

One issue that must be addressed is the possibility that due to lost efficiency as a result of installing cooling towers, a power plant would burn more fuel in an effort to make up for lost electricity generation and thus produce increased air emissions. This should not be an issue at BPS, however, because the permittee has indicated that due to the fixed steam capacity of the boilers at BPS, the plant *cannot* actually burn more fuel to make more steam and generate more electricity in response to efficiency losses due to cooling towers.[221] Instead, any needed lost megawatt-hours from BPS due to cooling tower-related penalties would be replaced by generation at other plants. It is more than likely that these other plants will be similar or cleaner burning facilities, given that BPS is an old coal burning plant. Therefore, the marginal penalties

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[220] See December 2001 USGenNE 316(a) and (b) Demonstration, Vol. IV, App. H., p. 4-4.

[221] See id., Vol. III, App. G, (Tab: Dynamic Cost Analysis at 4). See also EPA TDD 2001 - New Facilities, pp. 3-31 to 3-33.

discussed above are likely, in turn, to lead to no changes in air pollutant emissions at BPS and only very marginal changes across the Region.[222]

Moreover, it must be understood that any emission increases would be limited by applicable air pollution standards. Since the MA DEP has recently promulgated new air pollution standards that apply to BPS and will require significantly reduced air emissions from the plant (and several other major, older power plants), the overall air emissions from this plant will be substantially reduced compared to current levels regardless of whether the plant burned marginally more fuel to make up for efficiency losses due to cooling towers.[223] In addition, these new regulations will also lead to substantial overall emission reductions in Massachusetts. EPA reiterates that any new cooling towers will be subject to air permitting requirements and will obviously need to satisfy all applicable air pollution standards (e.g., standards for particulate emissions). Moreover, it is more than likely that these other plants will be similar or cleaner burning facilities, given that BPS is an old coal burning plant. Therefore, the marginal efficiency and auxiliary power penalties discussed above are likely to lead to no changes in air pollutant emissions at BPS and only very marginal changes across the region.

4.5.1b Noise

Noise could be a concern if retrofitted wet mechanical draft cooling towers are located very near to sensitive receptors (e.g., residences). Noise comes principally from the fans and possibly from water falling within the towers.[224]

BPS is essentially surrounded on three sides by water and on the fourth side by part of the Town of Somerset. The permittee indicates that it would locate any cooling towers in a north-central area of the site.[225] The nearest residences to this north-central area are approximately 1900 feet to the east in Somerset and approximately 1900 feet to the west across the Lee River in Gardners Neck in Swansea.[226] Before installing and operating any mechanical draft cooling towers, the

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[222] December 2001 USGenNE 316(a) and (b) Demonstration, Vol. III, App. G, (Tab: Dynamic Cost Analysis, at 4).

[223] See 310 CMR 7.29.

[224] See EPA TDD 2001 - New Facilities, p. 3-35.

[225] See December 2001 USGenNE 316(a) and (b) Demonstration, Vol. IV, App. H, Figures 3.3-1, 2.2-1; NEPCO January 15, 1998 NPDES Permit Application, Figure 1.

[226] See Figure 7.3-1, “Brayton Point, Somerset, MA, Distances from Proposed Cooling Towers to Sensitive Receptors (EPA, January 24, 2002).

permittee would be required to conduct an appropriate noise analysis to ensure compliance with any applicable State and/or local noise standards. (There are no applicable Federal noise standards.) That being said, EPA believes based on current information that the site configuration and the availability of various types of noise mitigation (e.g., low noise fans, trees), if any is needed, should enable retrofitting of mechanical draft cooling towers at BPS while achieving compliance with applicable regulatory standards to prevent unacceptable impacts to the nearest receptors.[227] If any special noise mitigation measures were required, it could increase the cost of cooling towers but not likely by a particularly significant degree.

The amount of noise generated is essentially proportional to the number of cooling cells and fans required for the options. Thus, the most noise undoubtedly would result from a conversion of all four units to closed-cycle cooling using mechanical draft cooling towers, as that would involve 72 cooling tower cells and fans. Noise from the conversion of Units 2 and 3 (37 cells) or just Unit 3 (22 cells and fans) and from the Enhanced Multi-Mode option (20 cells and fans) would be proportionately less.[228] In fact, the Unit 3 Closed-Cycle and Enhanced Multi-Mode options would yield similar noise based on the similar number of cooling tower cells and fans required.[229] None of this is to say that any noise issues cannot be controlled, and the permittee does not argue that noise presents a "fatal flaw" for any unit-specific or multi-mode cooling tower option.[230]

4.5.1c Visual/Aesthetic Impacts

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[227] See, e.g, December 2001 USGenNE 316(a) and (b) Demonstration, Vol. IV, App. H, p. 3-3; id., Vol. I, Executive Summary, p. 8 n.7; EPA Economic and Engineering Analysis, App. A, p. 14; Nuclear Regulatory Commission, Generic Environmental Impact Statement for License Renewal of Nuclear Plants (NUREG-1437 Vol. 1), § 4.3.7 (December 14, 2001); EPA TDD 2001 - New Facilities, p. 3-35.

[228] See December 2001 USGenNE 316(a) and (b) Demonstration, Vol. IV, p. 3.3-27.

[229] See id. at pp. 3.3-27, 4-2, 4-5, 3.3-3. Moreover, the permittee did not explain why some or all of the cooling towers could not be built on the southwest portion of the site near the discharge canal, and further from the nearest residences, that the permittee has identified would be used for the helper cooling tower option if it were selected. See December 2001 USGenNE 316(a) and (b) Demonstration, Vol. IV, App. H, Figure 3.2-23. The permittee was asked this question at the January 29, 2002 meeting, and the permittee indicated that doing so would be significantly more expensive due to the need for lengthier "piping runs." See January 30, 2002 e-mail from Mark Stein, EPA, to David Webster, EPA, et al. ("Subject: Brayton - FYI"). In any event, if noise were a problem, locating the towers further south might be another way to mitigate those impacts, though apparently at some cost.

[230] See id.

With respect to visual and aesthetic impacts, it cannot be denied that adding wet mechanical draft cooling towers will add additional visible industrial facilities to BPS; however, EPA does not believe that this ultimately should be regarded as a significant unacceptable impact when the environmental benefits of retrofitting such cooling towers are considered. In addition, the permittee has not argued that such impacts should be viewed as unacceptable.

BPS is already a huge industrial facility with large buildings, tall smoke stacks and electrical transmission lines on the site. Thus, mechanical draft cooling towers would not be out of character with the surroundings at the plant.[231] The cooling towers included as part of the Closed-Cycle Unit 3 and Closed-Cycle Entire Station options would be built on fill at grade elevation +30 feet msl and are expected to be 65 feet above grade, with the top of the tower at around +95 feet msl). This would be shorter than the three existing 350-foot smoke stacks, the one existing 500-foot smoke stack, and the largest building on the site.[232] The cooling towers included as part of the Enhanced Multi-Mode option would be slightly taller, at 67 feet above grade, with the top of the tower at +97 msl. The four towers included as part of the Helper Cooling Tower option would be located behind an earthen berm back from the eastern shore of the existing discharge canal; approximately 250,000 cubic yards of earth that would have to be removed in order to locate the towers at the required elevation of approximate grade elevation 18.0 feet would be used to create the earthen berm as well as other barriers or roadways that would aid in visually blocking the towers.

The permittee does not contend that any of these options would present an unacceptable visual impact. EPA agrees with the permittee on this point. The mechanical draft cooling towers associated with each of the unit-specific and multi-mode cooling tower options should not have the sort of dramatic adverse visual impact that would be associated with conventional natural draft cooling towers, which typically are much taller than mechanical draft towers. That being said, EPA also agrees with the permittee that somewhat greater visual impacts might be imposed by the Closed-Cycle Entire Station option because more cooling tower cells mean additional visible facilities.[233]

In addition, it is possible that under certain meteorological conditions, mechanical draft cooling towers would emit a visible plume into the air or create fog that could constitute an adverse visual

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[231] See Public Service Commission of Wisconsin/Wisconsin Department of Natural Resources, Final Environmental Impact Statement, Badger Generating Company, LLC, Electric Generation and Transmission Facilities (June 2000, 9340-CE-100), Executive Summary, p. 6.

[232] See December 2001 USGenNE 316(a) and (b) Demonstration, Vol. IV, pp. 3.3-4, 3.3-10.

[233] Id., pp. 3.3-3, 4-5.

impact. (The possible plume effects on traffic safety are discussed further below.) This could occur when ambient air temperatures are low, as compared to plume temperatures, and ambient humidity levels are high. The former condition promotes plume cooling and condensation, whereas the latter condition inhibits evaporation of the water in the plume. The direction and persistence of the plume would be determined by a number of factors including wind speed and direction, relative temperatures and humidity, the time needed for evaporation and dispersion, and the design of the cooling towers in question. Typically, a vapor plume will not be visible to off-site observers and or will dissipate after traveling a short distance due to dispersion and evaporation.[234]

With respect to potential visual impacts from a visible plume from mechanical draft wet cooling towers at BPS, EPA notes that while our October 1982 Permit Modification Determination indicated that salt drift was the primary problem with the former Unit 4 spray pod cooling system, which sprayed warm water directly into the air for cooling, EPA stated that the system also created fog that was an undesirable impact for the local community.[235] EPA believes that any fogging from new mechanical draft cooling towers would be either nonexistent or much less than was experienced with the old spray pod system. Mechanical draft towers, which are under consideration as BAT for reducing thermal discharges from BPS, do not throw the water directly into the air. Moreover, the permittee proposes that at BPS, these towers would be equipped with drift eliminators that would remove water droplets and reduce drift to a rate of .0005%.[236] This would mean a vastly reduced tendency to create visible fog as compared to the spray pod system and should reduce the density of any visible plume. Moreover, any fogging that did occur would typically be most severe on the plant site close to the towers. Finally, during at least some of the conditions when cooling tower fog might occur, naturally occurring fog would also be likely to occur in the coastal environment of BPS.[237] Under such conditions, fogging from the cooling

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[234] See EPA TDD 2001 - New Facilities, p. 3-33; Badger Power EIS, at 54; Public Service Commission of Wisconsin/Wisconsin Department of Natural Resources, Final Environmental Impact Statement, Badger Generating Company, LLC, Electric Generation and Transmission Facilities (June 2000, 9340-CE-100), Executive Summary, p. 6; “AES Londonderry Highlights” (AES, Inc., January 18, 2002), p. 6.

[235] See October 1982 Permit Modification Determination, pp. 19-20.

[236] See December 2001 USGenNE 316(a) and (b) Demonstration, Vol. IV, App. H, pp. 3-3, 3.3-3. See also 39 Fed. Reg. 36189 (October 8, 1974).

[237] See March 4, 2002 memorandum from Mark Stein, EPA, to Brayton Point NPDES Permit File (“Memorandum to File re 2/21/02 Visit to Brayton Point Station for Meeting”).

towers would present only a small marginal increase over background conditions.[238]

In sum, EPA does not believe that the visible plume or any fogging from the cooling towers should be regarding as imposing an unacceptable adverse visual/aesthetic impact. In any event, the permittee would be required to satisfy all applicable air emission standards.

4.5.1d Salt Drift

With any salt water cooling tower, one must consider the issue of salt emissions from the towers. This should not be a significant problem at BPS, however, because the towers can be equipped with drift eliminators that reduce drift to 0.0005%. As the permittee has indicated, this would produce a rate of drift "several orders of magnitude lower than the total emissions from the past operation of the Unit 4 spray canal."[239] It would also produce "salt deposition and saline air concentrations that represent only a slight increase over ambient coastal conditions."[240] However, to the extent that residential icing caused by salt drift is actually an issue, the concern would be greater from the options that involve more cooling towers and the placement of the cooling towers at the site. Any cooling towers that are installed and operated at BPS will have to comply with all applicable air emissions requirements (e.g., particulate emissions).

4.5.1e Energy

As discussed in Section 4.4, one detriment of switching BPS from open-cycle cooling to closed-cycle cooling is that the change would marginally decrease the generating efficiency of each

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[238] USGenNE's plume modeling analysis predicts that, on average, over the course of a year, a 20-cell cooling tower would yield six hours of "plume-induced" fog at nearby receptors as compared to 336 hours of natural "background fog" (i.e., a less than 2 % increase). See December 2001 USGenNE 316(a) and (b) Demonstration, Vol. III (Tab: Section 308 Information Request Submittal - 9/10/01, Report on Fogging and Icing Effects Associated with Cooling Towers at Brayton Point Station (September 2001), App. B, p. 1 (Table: Hours of Plume Induced Fogging and Icing Summary). While this analysis was performed for a different purpose, it gives an idea of the relatively small marginal effect of the cooling towers on fog.

[239] See December 2001 USGenNE 316(a) and (b) Demonstration, Vol. IV, App. H, p. 3-3, 3.3-3. See also 39 Fed. Reg. 36189 (October 8, 1974).

[240] December 2001 USGenNE 316(a) and (b) Demonstration, Vol. IV, App. H, p. 3-3. See also EPA TDD 2001 - New Facilities, pp. 3-34 and 3-35; January 1997 NEPCO Report, p. 3-21.

converted unit ("efficiency penalty").[241] In addition, the amount of electricity that a converted unit generates for sale would be further reduced because a certain amount of energy would have to be used to run the fans and pumps utilized in a mechanical draft cooling tower ("auxiliary power penalty").[242]

EPA estimates that as a result of conversion to wet mechanical draft cooling towers, assuming a 100% load factor, the annual efficiency losses for BPS would be approximately 0.29% for Units 1, 2 and 3, and 0.09% for Unit 4 (assuming current levels of piggyback operations).[243] These efficiency losses would increase to 0.75% for Units 1, 2 and 3, and 0.18% for Unit 4, assuming a load factor of 67%.[244] Since Units 1, 2 and 3 are base-load units with a capacity factor of approximately 80%, the penalties are expected to be in between the two sets of figures.[245] Because Unit 4 has a much lower capacity factor of around 20%, its penalty figures would likely be somewhat higher than those for the 67% load factor; however, because Unit 4 operates less often than the other three units, the efficiency penalty for that unit would have a relatively smaller effect on the overall efficiency of the plant.[246] It should be noted that EPA's estimated efficiency penalties for the Enhanced Multi-Mode, Closed-Cycle Unit 3, and Closed-Cycle Entire Station options range from 58% to 77% lower than those predicted by the permittee.[247]

The permittee also predicts that the unit-specific cooling options will result in greater lost generation than its Enhanced Multi-Mode option, because the multi-mode system has "more flexibility to operate at a higher performance relative to the structure's size under a greater variety of atmospheric conditions than any of the other cooling tower alternatives."[248] This relates, at least in part, to the permittee's predictions of plume outages for the unit-specific options but not

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241 See EPA TDD 2001 - New Facilities, § 3.3.2.

242 See id., § 3.3.3.

243 See SAIC Report (March 15, 2002), Table 9. See also EPA TDD 2001 - New Facilities, Table 3-14.

244 See SAIC Report (March 15, 2002), Table 9. See also EPA TDD 2001 - New Facilities, Table 3-15.

245 See EPA TDD 2001 - New Facilities, p. 3-10.

246 See SAIC Report (March 15, 2002), p. 21.

247 Id., Table 10.

248 December 2001 USGenNE 316(a) and (b) Demonstration, Vol. IV, p. 4-4. See also id., Table 4-1.

for the multi-mode options. As discussed in this determination document, however, EPA has concluded both that it is uncertain that the plume-related problems will be as significant as the permittee predicts, and that there are other methods for controlling any such problems than resorting to unit outages.

In light of our consultant's analysis, EPA believes the permittee's estimates of the auxiliary power penalties that it would incur are reasonable.[249] For certain of the cooling options, the Agency's estimates are lower, whereas for others, its estimates are higher.[250]

On one level, these efficiency and auxiliary power penalties represent an economic issue (i.e., lost revenues due to reduced sales of electricity). Therefore, the company considered them in its economic evaluation of the alternatives, and EPA has done the same.[251] On another level, these penalties raise energy supply issues that should be considered. Having done so, however, EPA does not believe that these penalties are significant from an energy perspective, especially when considered in light of the major reduction in adverse impacts from thermal discharges that could be provided by a closed-cycle cooling system.

With regard to energy supply, EPA's research indicates that New England has an adequate power supply at present and is predicted to have an adequate supply moving into the future, in part because of the construction and proposal of new power plants that have added, and will continue to add, generating capacity to the supply inventory in the Region.[252] Therefore, neither the small marginal loss in efficiency nor the small marginal increase in energy use that would result from converting to closed-cycle cooling at BPS would present a significant problem for the Region's energy supply.[253] Moreover, as new, more efficient plants continue to come on line, the overall

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[249] See SAIC Report (March 15, 2002), p. 30.

[250] See id., Table 7. See also EPA TDD 2001 - New Facilities, pp. 3-22 to 3-30, Table 3-20.

[251] Compare December 2001 USGenNE 316(a) and (b) Demonstration, Vol. III, App. G (Tab: Dynamic Cost Analysis) with Abt Report (April 5, 2002), pp. 21-22.

[252] See, e.g., EPA-New England, Energy Fact Sheet (February 12, 2001); "NEPOOL Forecast Report of Capacity, Energy, Loads and Transmission, 2001 - 2010 (ISO-NE: April 1, 2001), pp. 1-2 (Section I Summaries, Summer and Winter System Capabilities and Peak Load Forecasts).

[253] See SAIC Report (March 15, 2002), Tables 6, 7, 9, 10 and 11 (permittee and SAIC independent estimates of reduction in energy produced for sale by BPS due to Closed-Cycle Entire Station option are 3.3% and 2.6%, respectively). See also EPA TDD 2001 - New Facilities,

efficiency of the Region's energy supply will increase even if BPS has a marginal loss of efficiency due to shifting entirely or partially to closed-cycle cooling. For example, the proliferation of new, combined-cycle power plants will significantly increase the overall efficiency of the Region's power supply and more than offset any lost efficiency from closed-cycle cooling at BPS.[254]

In addition, there is at least one potentially significant energy *benefit* provided by shifting to closed-cycle cooling. The permittee has determined that improved cooling would enable it to operate more at peak demand times during the hottest days of the year – assuming compliance with applicable air pollution standards – because the plant would less frequently threaten to exceed the permit's current maximum temperature limit of 95° F.[255] This not only would enable the plant to sell more electricity during the peak pricing period, which would benefit the permittee economically, but it also might benefit the Region's overall power supply because that supply is most likely to be overstretched, if ever, during the hottest days of the year when peak demand occurs.[256] With retrofitted wet cooling towers, BPS would be able to generate more power to help meet this peak demand. (It should also be noted, however, that this benefit could be marginally offset by the fact that efficiency penalties are likely to be somewhat greater during the hot summer days.)[257]

4.5.2 Other Impacts

4.5.2a Traffic Safety (Fogging, Icing)

Another issue that EPA must consider in determining whether any of the unit-specific or multi-mode wet cooling tower options are BAT for reducing thermal discharges from BPS is whether there would be emissions of mist (i.e., water droplets) or water vapor that could cause a traffic hazard on nearby roadways due to fogging or icing. Protecting public health and safety is at the top of the priority list for EPA and the other involved state and federal agencies. Therefore, we take this issue seriously and have evaluated it from several perspectives.

Tables 3-1, 3-2, 3-14, 3-15, 3-20.

[254] See EPA TDD 2001 - New Facilities, p. 3-8.

[255] See December 2001 USGenNE 316(a) and (b) Demonstration, Vol. III, App. G, (Tab: Dynamic Cost Analysis, p. 4).

[256] See Abt Report (April 5, 2002), pp. 12, 23-24.

[257] See EPA TDD 2001 - New Facilities, p. 3-9.

The permittee has stated that it believes that wet cooling towers at BPS would emit a vapor plume that could cause a fogging/icing traffic safety concern on nearby portions of Route 195 and the Braga Bridge. The permittee also has stated that it would have to shut down *the cooling towers* during these periods to eliminate this potential hazard.[258] According to the permittee, this would substantially increase the cost of the unit-specific options because shutting down the cooling towers would also require shutting down the associated generating units. The permittee also states, however, that these increased costs could be avoided for the Enhanced Multi-Mode option, because multi-mode cooling towers could be bypassed if necessary to prevent fog or ice, and the generating units could continue to operate. This contributes to the permittee's preference for the Enhanced Multi-Mode option from the perspective of cost and operational flexibility.

Based on current information, EPA's conclusion with regard to the fogging/icing traffic safety issue is that it is uncertain whether this problem would occur to a significant degree if wet cooling towers are installed at BPS, but that there are several ways to eliminate the problem if it does occur. Methods for managing this potential problem are discussed below, along with the uncertainties surrounding the magnitude of the problem. Following that discussion, reasons for uncertainty regarding the likely extent of any problem are presented.

Mechanical draft cooling towers can be equipped with highly efficient mist (or "drift") eliminators that can nearly eliminate the emission of water droplets (and salt) by the tower. As the permittee explains, such drift eliminators can achieve a drift rate of .0005%, which would represent only a very small marginal increase over the moisture naturally in the air in a coastal environment such as that around BPS.[259] Thus, with the use of drift eliminators, the permittee should be able effectively to prevent mist emissions from any mechanical draft cooling towers retrofitted at BPS, and mist emissions should not significantly contribute to any fogging or icing in the vicinity of the Station.

As the permittee notes, however, mechanical draft wet cooling towers also emit water *vapor* (as opposed to *mist*), which under certain meteorological conditions can condense and cause fog and/or ice on road surfaces.[260] The permittee has conducted a site-specific analysis, based on a 20-cell cooling tower, that predicts that a mechanical draft cooling tower at BPS would emit a plume of water vapor that under certain meteorological conditions could cause fogging or icing

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[258] See, e.g., December 2001 USGenNE 316(a) and (b) Demonstration, Vol. IV, App. H, p. 3-3.

[259] See id., pp. 3-3, 3.3-3. See also 39 Fed. Reg. 36189 (October 8, 1974).

[260] See December 2001 USGenNE 316(a) and (b) Demonstration, Vol. IV, App. H, p. 3-3 n.7.

on certain nearby "receptors.[261] In addition, the permittee has concluded that this fogging or icing could cause a traffic safety problem on Route 195 and the Braga Bridge.[262]

The permittee's analysis is based on a "CALPUFF" modeling analysis that uses among other things, meteorological data from the T.F. Green Airport in Providence, Rhode Island, from 1989 to 1993. This analysis estimates that in an average year, there are 343 hours of "background fog and ice" (336 hours of fog and seven hours of ice) near the plant, and that the cooling tower would add seven hours of "plume-induced fog and ice" (six hours of fog and one hour of ice). This represents only a two percent (2%) increase over background conditions. In addition, the analysis predicts that only four of these plant-added hours of fog or ice would actually "impact the highway and bridge."[263]

Nevertheless, the permittee's modeling analysis also concludes that this vapor plume-induced fogging or icing threat to the highway or bridge would require cooling tower "plume outages" an average of 54 times a year for an average total duration during the year of 166 hours.[264] This is more than 41 times the number of predicted hours of plume-induced fog or ice at the highway and bridge (4 x 41.5 = 166). The permittee explains that this is because in order to *prevent* fog or ice *before* it occurs, the permittee would have to shut down the tower and generating unit whenever certain meteorological conditions occur that *might* lead to fog and ice, and that such conditions occur more frequently than actual fog or ice and may persist for several hours at a time.[265] The permittee adds that the problem would be more severe if more than 20 cooling tower cells were utilized at the power plant.[266]

The permittee also states that generating unit outages would be made even longer due to the five

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[261] See id., Vol. III (Tab: Section 308 Information Request Submittal - 9/10/01, Report on Fogging and Icing Effects Associated with Cooling Towers at Brayton Point Station (September 2001).

[262] Id., p. 3-3.

[263] Id., Vol. III (Tab: Section 308 Information Request Submittal - 9/10/01, Report on Fogging and Icing Effects Associated with Cooling Towers at Brayton Point Station (September 2001), p. 9 and App. B, p. 1 (Table entitled "Hours of Plume Induced Fogging and Icing Summary").

[264] Id.

[265] Id., p. 8.

[266] See id., Vol. IV, App. H, pp. 3-3, 3-4, 4-6; id., Vol. III, App. G (Dynamic Cost Analysis, at 7).

to 12 hours necessary to get a generating unit back on-line after it has been taken off-line.[267] Indeed, in the permittee's Dynamic Cost Analysis, the permittee assumes that *648* hours of generating unit outages per year would occur for the Closed-Cycle Unit 3 option, based on 54 outages and 12 hours of unit restart time, and that *486* hours per year of outage for Units 1, 2 and 3 would occur for the Closed-Cycle Entire Station option based on 54 outages with nine hours of restart time per unit.[268] The 648 and 486 hours of predicted outage are *162* and *121* times more than the four hours of additional fog or ice actually predicted by the permittee's model to affect the highway and bridge in the average year.

Based on its conclusion that water vapor plumes would require cooling tower shutdowns and associated generating unit shutdowns for the unit-specific cooling tower options, the permittee has included a substantial cost for hundreds of hours of "plume outages" for these options. The cost of these outages reflects lost profits due to the outages.[269] The permittee has not included such costs for the Enhanced Multi-Mode option because that option allows for cooling tower bypass.

EPA has evaluated the plume/safety issue from a number of perspectives. Most importantly, EPA has concluded that to the extent a traffic safety issue may arise, there would be several means of adequately controlling it. First, as the permittee has indicated, if necessary, a cooling tower and associated generating unit could be shut down for a short period to avoid a safety issue. The permittee states that it would expect to undertake such shutdowns if necessary. With the multi-mode options, of course, the permittee could shut down the cooling towers but continue to operate the generating units. Likewise, EPA believes that the unit-specific options could be engineered to allow the cooling towers to be bypassed so that the generating units could be operated in once-through mode during the period of any plume-related safety hazard. As discussed above, EPA has learned that a number of power plants around the United States have cooling towers that are only used some of the time. Thus, it is clear that this is a practicable approach. Indeed, this ability to bypass the cooling towers is one key aspect of the multi-mode cooling tower operations. This approach may add some cost, due to piping or pumping needs, but any such costs would most likely be less expensive than the permittee's predicted generating unit outages. EPA's evaluation estimated what these costs might be and found them to be less

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[267] See id., Vol. III (Tab: Section 308 Information Request Submittal - 9/10/01), Attachment A, p. 10.

[268] Id., Vol. III (Tab: Dynamic Cost Analysis), Unit 3 Conventional Closed Cycle Spread Sheet, p. 3.

[269] See id., Vol. IV, App. H, pp. 3-4 and 4-4, Table 4-1; Vol. III, App. G (Tab: Dynamic Cost Analysis, pp. 7-8; Tab: Section 308 Information Request Submittal - 9/10/01, p. 4).

than the cost of the outages.[270] (Costs are discussed more fully above.) Of course, the plant would still need to operate within its permit limits for flow, maximum-temperature, Δ-T, and Btu loadings, but this is also true for the multi-mode options.

Second, it might be feasible to develop an early warning system. When it is predicted that potentially hazardous fog or ice conditions might occur as a result of the cooling towers, instead of shutting the towers down, the permittee would notify the Massachusetts Highway Department in order to initiate icing controls (e.g., salting of roads) or activate lighted cautionary signs warning of potential fog conditions. As discussed above, the permittee's analysis predicts only a small marginal increase in fog and ice conditions from background, and the Massachusetts Highway Department already has programs in place for dealing with these background conditions.[271]

Third, there are plume abatement technologies that can be utilized with mechanical draft cooling towers to substantially reduce or eliminate vapor plume effects. Described above in Section 4.3.2, these technologies are generally referred to as "wet/dry" or "hybrid" cooling towers.[272] Switching to hybrid cooling towers, however, would significantly increase the capital cost of the equipment as compared to retrofitting wet mechanical draft cooling towers, and reduce electrical generation efficiency somewhat more than the use of wet cooling towers would. EPA's consultants estimate that adding plume abatement could approximately double the capital cost of the cooling towers without plume abatement.[273]

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[270] See SAIC Report (March 15, 2002), p. 13, Table 5; Abt Report (April 5, 2002), p. 8.

[271] April 9, 2002 memorandum by Damien Houlihan, EPA ("Re: Record of 4/9/04 Conference Call with MA DEP and Massachusetts Highway Department").

[272] See EPA TDD 2001 - New Facilities, at p. 3-33; January 4, 2002 telephone memorandum from Sharon Zaya, EPA, regarding Call with Ken Daledda, Bergen Station, New Jersey; Materials obtained from Marley Cooling Technologies, Inc.; Public Service Commission of Wisconsin/Wisconsin Department of Natural Resources, Final Environmental Impact Statement, Badger Generating Company, LLC, Electric Generation and Transmission Facilities (June 2000, 9340-CE-100), Executive Summary, p. xii; "AES Londonderry Highlights" (p. 6 of 7) (AES, Inc., 1/18/02).

[273] SAIC Report (March 15, 2002), p. 14, Table 5. See also 66 Fed. Reg. 65283 (Dec. 18, 2001) (costs of dry cooling compared to costs of hybrid cooling and wet cooling); January 31, 2002 e-mail from Richard Scogland, Marley Cooling Technologies, to Sharon Zaya, EPA ("Subject: Cost Estimate for Marley's Clearflow"); February 1, 2002 e-mail from Kenneth Detmer, Wisconsin Public Service Commission, to Mark Stein, EPA ("Subject: Cooling

Ultimately, of course, the permittee may choose whichever method it wants from the several practicable approaches should the need for plume abatement arise. The choice of method would most likely be determined by the cost and the permittee's operational preferences. At present, the permittee indicates that it prefers the Enhanced Multi-Mode option because, among other things, the cooling towers could be shut down to avoid plume hazards without requiring generating unit outages. This option, however, would achieve lower thermal discharge reductions than any of the unit-specific options. For these options, the permittee indicates that it would engage in generating unit shutdowns to prevent plume-related hazards, but that these outages would result in substantial cost to the company. EPA has concluded, however, that engineering a "bypass" of the cooling towers would likely be a less expensive, more practicable alternative in the long run. Alternatively, an early warning system in conjunction with the Massachusetts Highway Department might be sufficient to avoid either outages or cooling tower bypasses. This would require further consultation and coordination between the Department, the permittee, EPA and the MA DEP. A more expensive option, but one that would maximize operational flexibility and the thermal discharge and flow reductions achievable by the unit-specific options, would be to install hybrid cooling. (The company also might want to consider, at a minimum, installing cooling towers that are amenable to retrofitting with plume abatement technology at a later date.)

Having addressed the issue of how to abate any plume hazards, EPA must state that based on current information, we believe it is uncertain that cooling towers at BPS would emit a vapor plume that would become a traffic hazard on the highway or bridge. It is also uncertain whether the hours of potential hazard predicted by the permittee would actually require generating units using cooling towers to be shut down for hundreds of hours per year in order to achieve our clear priority of ensuring public safety. (EPA recognizes, however, that if plume hazards are a problem, this problem could be worse for the Closed-Cycle Entire Station option.[274])

There are several reasons why EPA believes that there is substantial uncertainty regarding whether the plume problem will be as severe as the permittee asserts. First, EPA has reviewed the permittee's air modeling analysis and has a number of concerns and questions about it. While the CALPUFF model used by the permittee is certainly acceptable for certain air modeling purposes, there is a significant question as to whether the model and the pre- and post-processors used with the model were appropriate for the purpose of assessing the plume issue in this case, especially when compared to other models that have been developed more specifically for

Towers"); January 4, 2002 telephone memorandum from Sharon Zaya, EPA, regarding Call with Ken Daledda, Bergen Station, New Jersey.

[274] See December 2001 USGenNE 316(a) and (b) Demonstration, Vol. III, App. G (Tab: Section 308 Information Request Submittal - 9/10/01, at 6).

modeling cooling tower plumes (such as the SACTI model developed by EPRI).[275] EPA does not presently believe that the permittee has established the reasonableness of its modeling analysis.

Second, experience of other plants does not appear to corroborate the threat suggested by the permittee. EPA spoke with representatives of two power plants that use wet mechanical draft cooling towers, and learned that any icing concerns that do exist at these plants are limited to areas very close to the cooling towers (within a few hundred feet) and have not affected roadways or bridges within relatively short distances from the towers (in one case, within approximately a half-mile, and in another case, within about 700 feet).[276] Neither icing nor fogging appeared to create a problem in any of the situations referenced above. One plant did install a wet/dry system to enable it to remove a visible plume due to initial concerns over potential highway icing or fogging, but this plant reported to EPA that the plume did not turn out to pose a fogging/icing hazard in practice. This plant only uses the "dry components" to mitigate an aesthetic issue related to a periodically visible plume of fog during humid conditions.[277]

Third, EPA notes that in the January 1997 NEPCO Report, the permittee predicted that although "incidence of ground fog can occur during periods of high relative humidity, cool weather, moderate to low winds and inversions or some combination thereof ... [,i]t is unlikely however that the fog would extend further than 500 to 1,000 feet downwind of the towers."[278] No concern

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[275] See February 1, 2002 e-mail from Kenneth Detmer, Wisconsin Public Service Commission, to Mark Stein, EPA ("Subject: Cooling Towers") (expressing opinion that CALPUFF model works for wet/dry cooling tower evaluations, but uncertain about using it for traditional wet towers); January 3, 2002 memorandum from Brian Hennessey, EPA, to Mark Stein, EPA ("Air Impact Analysis of Evaporative Cooling for Brayton Point Generating Station (Somerset, Massachusetts)"); December 11, 2002 e-mail from John Irwin, EPA, to Warren Peters, EPA, et al. (cc: Brian Hennessey, EPA, et al.); December 5, 2002 e-mail from Warren Peters, EPA, to Brian Hennessey, EPA (cc: Joe Touma, EPA, John Irwin, EPA, et al.); January 4, 2002 telephone memorandum from Sharon Zaya, EPA, regarding Call with Ken Daledda, Bergen Station, New Jersey.

[276] January 4, 2002 telephone memorandum from Sharon Zaya, EPA, regarding Call with Ken Daledda, Bergen Station, New Jersey; December 12, 2001 memorandum from Mark Stein to Brayton Point NPDES Permit File ("Brief Notes on an Issue Discussed During Conference Call with John Gulvas of Consumers Energy and the Palisades Nuclear power station in Covert, Michigan"); 39 Fed. Reg. 36192 (October 8, 1974).

[277] January 4, 2002 telephone memorandum from Sharon Zaya, EPA, regarding Call with Ken Daledda, Bergen Station, New Jersey.

[278] January 1997 NEPCO Report, p. 3-21.

was expressed about off-site icing. Furthermore, in the December 2001 USGenNE 316(a) and (b) Demonstration, the permittee explained that the helper towers are identical to the mechanical draft cooling towers, and that even for the 48-cell helper tower, "[f]ogging during cool wet weather, and when temperatures are cold enough, icing are expected to rarely be an issue with the helper tower design since these are local effects and the helper towers are located near the discharge canal and further away from the highway and bridge than the multi-mode or closed-cycle alternatives."[279] The area near the discharge canal appears to be only about 500 feet or less further from the highway and bridge.[280]

Although the permittee expresses particular concern over fogging and icing impacts to Route 195 and the Braga Bridge, the bridge appears to be approximately 5000 feet (0.95 miles) from where the cooling towers would be located, while the nearest point on Route 195 is approximately 2164 feet away (0.41 miles), and the nearest residential streets are approximately 1900 feet away (0.36 miles).[281] Moreover, moving the unit-specific cooling towers further to the south on the site, into the area where the permittee suggests the Helper Cooling Tower option could be located, would add even more distance and make any potential problems even less likely.[282]

Fourth, as a matter of common sense, it does not seem that the problem should be severe enough to require hundreds of hours of generating unit outages. The permittee's own analysis confirms that the roads and highways in the coastal environment of Mount Hope Bay periodically experience icing and fogging from natural conditions that is managed by local highway safety programs. The permittee's analysis predicts that a 20-cell cooling tower would add only a small marginal increase in fogging and icing (around 2%) over background conditions in an average year. This average increase is well within the range of natural fluctuation in background conditions. Again, the permittee predicted that in an average year only one hour of "plume-induced ice"and only six hours of "plume-induced fog" would occur, as compared to 343 hours of "background fog and ice" (a 2 % increase). Only four of these hours of plume-induced fog or ice were predicted to "impact the highway and bridge." In response to this, the permittee predicts that literally hundreds of hours of unit outages per year would be needed to eliminate this

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[279] See December 2001 USGenNE 316(a) and (b) Demonstration, Vol. IV, App. H, pp. 3-1, 3.2-1, 3.2-19.

[280] See Figure 7.3-1, "Brayton Point, Somerset, MA, Distances from Proposed Cooling Towers to Sensitive Receptors (EPA, Jan. 24, 2002).

[281] See id.

[282] See December 2001 USGenNE 316(a) and (b) Demonstration, Vol. IV, App. H, Figures 3.2-19, 3.2-23.

potential plume effect.[283] As discussed above, this seems unrealistic based on common sense and experience at other plants, and we are not yet persuaded of the validity of the permittee's modeling analysis.[284]

Nevertheless, as stated above, the permittee proposes to address possible plume hazards from the unit-specific options by shutting down generating units and their associated cooling towers during conditions when it believes the risk exists. As a result, the permittee includes the cost of such outages in the costs of these closed-cycle cooling tower options. Because of EPA's uncertainty about the likely need for these outages, EPA has evaluated the costs of these options under the following three scenarios: (a) accepting the permittee's estimate of plume outages, (b) assuming half the plume outages predicted by the permittee, and (c) assuming no plume outages.

4.5.2b Plant Reliability, Operational Flexibility and Construction-Related Outages

The permittee argues that the unit-specific cooling tower options, but not the Enhanced Multi-Mode option, reduce plant reliability because of the potential for plume-related outages in the

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[283] See id., Vol. III (Tab: Section 308 Information Request Submittal - 9/10/01, Report on Fogging and Icing Effects Associated with Cooling Towers at Brayton Point Station (September 2001), p. 9 (of 13) and App. B, p. 1 (Table: Hours of Plume Induced Fogging and Icing Summary).

[284] It is worth noting that Badger Generating Company, LLC, an affiliate of PG&E operating in Wisconsin, proposed a new combined-cycle natural gas electric generating plant in the village of Pleasant Prairie, WI that would use hybrid wet/dry cooling towers to control any threat of fogging or icing on roadways surrounding the facility. With the hybrid cooling towers, the analysis concluded that only a few hours per year of fogging and/or icing would result on certain roads immediately surrounding the plant. There was no suggestion, however, that these few hours of predicted fog or ice required many times more hours of generating unit outages, or indeed any outages at all, to eliminate all possibility of any fog or ice. In addition, the company argued that "[o]n days of rain, fog, snowfall, or blowing snow . . . plant-induced fogging and icing would not be important, since there might already be fog and ice on Pleasant Prairie roads and drivers would already be more cautious." The Public Service Commission and the Department of Natural Resources of the State of Wisconsin considered the potential for additional fogging and icing to be a concern but were satisfied with the few hours that would be left after the installation of hybrid cooling. Thus, the State approved the facility recognizing the small number of hours of plant-induced fogging and/or icing that might occur. See Public Service Commission of Wisconsin/Wisconsin Department of Natural Resources, Final Environmental Impact Statement, Badger Generating Company, LLC, Electric Generation and Transmission Facilities (June 2000, 9340-CE-100), pp. xi, 73-74, 137-138.

winter attributed to fogging/icing problems.[285] Any problem in this regard would be more severe for the options using more cooling tower cells. As explained above, however, EPA believes that plume-related hazards of the magnitude suggested by the permittee are uncertain, and that there are methods of controlling any such hazards without generating unit outages.

Nevertheless, if such temporary outages were to occur, as predicted by the permittee, it would ultimately represent an economic issue to the permittee rather than an energy supply problem to the region. It is unlikely that any such temporary, intermittent outages would jeopardize the adequacy of the region's power supply because that supply is constituted and managed to respond to occasional scheduled and unscheduled outages while maintaining adequate power. Any plume-related outages would similarly be managed without supply shortfalls. In addition, as discussed above, adding cooling tower technology is expected to enable BPS to generate somewhat more electricity during peak summer demand periods. This may help the regional power supply at the time it is most stressed.

For the installation of any of the closed-cycle cooling tower options at BPS, the permittee also predicts generating unit outages "for the tie into ... the generating units ... [to] complete the cooling system conversion."[286] Unlike plume outages, construction outages are one-time events. Although any such outages would be sequenced to coincide with regularly scheduled maintenance outages, the permittee predicts that the construction outages would exceed the duration of the regular maintenance outages and, therefore, represent additional downtime for the units involved. The permittee predicts that these outages will be somewhat greater for the unit-specific options than the Enhanced Multi-Mode option.[287]

There is no reason to expect that these one-time outages should endanger the region's power supply. The regional power supply is already managed to accommodate periodic scheduled and unscheduled outages without a shortfall in capacity. There is nothing to suggest that the type of outages discussed here could not be handled in this manner. These outages could also, if necessary, be scheduled and sequenced to avoid peak demand periods. Ultimately, any such outages represent an economic issue for the permittee, and both EPA and the permittee have evaluated such outages in our economic analyses. It should also be noted here that EPA believes as an engineering matter that the permittee has overestimated the necessary construction outages based on research concerning other plants that have converted their cooling systems from once-through to closed-cycle cooling towers.

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[285] December 2001 USGenNE 316(a) and (b) Demonstration, Vol. IV, App. H, p. 4-3.

[286] Id., p. 4-5.

[287] See id., p. 4-4 and Table 4-1 (e.g., 5.5 months for Enhanced Multi-Mode option; 8 months for Closed-Cycle Unit 3 option).

4.5.2c Construction Effects

As the permittee states, all of the cooling tower options raise the likelihood of some "moderate" noise and truck traffic effects from construction activities.[288] It should also be noted that construction for new air pollution control equipment will be occurring during a similar timeframe. Ultimately, some construction effects cannot be avoided if improvements are to be made to reduce the plant's adverse water and air impacts on the environment; however, no filling of wetlands or tidelands should be needed for any of the construction. Moreover, the industrial nature of the site and existing facilities, as well as the large size and buffering capacity of the site, should moderate the impacts of construction. Any effects would be further reduced if the facilities were constructed in areas farther from local residences. Compliance with all local traffic and noise ordinances will be required.[289]

The single-unit and multi-mode cooling tower options have roughly similar construction periods of 13 months for the Unit 3 option and 16 months for the multi-mode options, whereas the Closed-Cycle Entire Station option has a longer construction period of 32 months.[290] Thus, construction effects would undoubtedly increase as more units are converted to new cooling systems.

4.6 Determination of Technology-Based Discharge Limits

Section 4.6 discusses the analyses presented above, evaluates whether any of the unit-specific or multi-mode cooling tower-based options under consideration is the Best Available Technology Economically Achievable (i.e., BAT) for reducing thermal discharges from BPS, and presents EPA's determination regarding the necessary NPDES permit requirements for BPS under CWA §§ 301(b)(2) and 304(b)(2). To the extent that this section reiterates matters that have been discussed and documented in earlier sections of this document, supporting references will not be repeated here.

In short, EPA evaluated numerous cooling system options to determine what might constitute BAT for reducing thermal discharges from BPS. Based on its own research and analysis as well as on information submitted by the permittee, EPA has concluded that the thermal discharge limits for BPS should be based on the discharge commensurate with converting Units 1, 2, 3 and

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[288] Id., p. 4-4.

[289] Given that fuel is currently barged to the plant, it *may* also be feasible to bring some materials to the site by water so as to minimize truck traffic on streets surrounding BPS.

[290] December 2001 USGenNE 316(a) and (b) Demonstration, Vol. IV, App. H, Table 4-1; Vol. V, App. B (Tabs B6, B7, B13, B15 and B16).

4 to closed-cycle cooling using mechanical draft wet cooling towers (i.e., the Closed-Cycle Entire Station option). Retrofitting the entire station with closed-cycle mechanical draft cooling towers would greatly reduce the total annual heat discharge from BPS to Mount Hope Bay, shrinking it to 0.8 TBTU from the 42 TBTU currently allowed under MOA II (a reduction of approximately 98%).

4.6.1 Introduction

BPS is the largest fossil fuel burning power plant in New England. With an operating capacity of approximately 1500 MW – approximately 1100 MW from coal-burning Units 1, 2 and 3, and 400 MW from oil/natural gas-burning Unit 4 – BPS produces about six percent of the electricity consumed by New England (at 2001 consumption levels).[291] As such, it is clearly an important contributor to New England's power supply at the present time.

The facility covers approximately 250 acres at the confluence of the Taunton and Lee Rivers. The four fossil-fueled electric power generating units are contained in boiler and turbine houses, which are connected in line to form the power plant. Maintenance facilities, laboratories and administrative offices are attached to the east side of the plant. Three 350-foot stacks for Units 1, 2, and 3, one 500-foot stack for Unit 4, and five fuel oil storage tanks with a combined capacity of 1,386,000 barrels are located south of the plant. A nine-acre, 600,000 ton-capacity coal storage area is located east of the oil storage area. A dredged channel is located along the west side of the coal storage area for ships delivering fuel to the station.

A spray cooling canal for Unit 4 condenser cooling water was built north of the plant but is now mostly filled in with structural fill from the coal units. Within the remains of the cooling canal loop are two wastewater treatment basins. Adjacent to the canal on the west and north sides are wastewater treatment sludge disposal trenches. Also on the north side of the plant and east of the former spray cooling canal are transmission lines, which run northeasterly off the station site onto a company right-of-way.

The four boilers inside the plant (one for each power generating unit) utilize coal, No. 6 fuel oil or gas. Units 1, 2, and 3 were put in service in August 1963, July 1964, and July 1969, respectively. They were originally designed to burn coal but were converted to burn oil in 1969. The units were converted back to burn coal in early 1982. Unit 4, designed to burn oil, was put into service in December 1974, with gas-fired capability added in 1992.

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[291] See Abt Associates, Inc., "Impact of Thermal Discharge Management and Air Pollution Control Options for Brayton Point Station on New England Electricity Market and Consumer Rates," p. 3 (May 8, 2002).

A once-through condenser cooling system with a design flow of 640,000 gpm is currently used for Units 1, 2 and 3. The condenser cooling system for Unit 4, originally closed-cycle, was converted to once-through operation with a design flow of 260,000 gpm beginning in July 1984. An additional once-through flow of 31,000 gpm is currently used by all four units for cooling water and other plant uses (e.g., service water). Condenser cooling water for each unit and service water for the station are currently discharged on the west side of the plant site and directed through a discharge channel to upper Mount Hope Bay. The 3,200-foot long discharge channel terminates at the southern tip of the plant site at a venturi designed to promote rapid mixing with the surrounding cooler water.

4.6.2 Brief Reiteration of Legal Standards

CWA §§ 301(b)(2) and 304(b)(2) require EPA to establish permit limits for thermal discharges based on the degree of control attainable by the Best Available Technology Economically Achievable (i.e., BAT). For point sources in the steam electric power generating point source category, such as BPS, EPA develops technology-based thermal discharge limits based on BAT using Best Professional Judgment (BPJ) under CWA § 402(a)(1), because there is no national effluent limitation guideline on the discharge of heat from these point sources.

For heat and other non-conventional pollutants, as well as for toxic pollutants, the CWA requires the achievement of

> effluent limitations for categories and classes of point sources, other than publicly owned treatment works, which ... shall require application of the best available technology economically achievable for such category or class, which will result in reasonable further progress toward the national goal of eliminating the discharge of all pollutants, as determined in accordance with regulations issued by the [EPA] Administrator pursuant to [CWA § 304(b)(2),] section 1314(b)(2) of this title, which such effluent limitations shall require the elimination of discharges of all pollutants if the Administrator finds, on the basis of information available to him ... that such elimination is technologically and economically achievable for a category or class of point sources as determined in accordance with regulations issued by the [EPA] Administrator pursuant to [CWA § 304(b)(2),] section 1314(b)(2) of this title ....[292]

This means that EPA must set limits that (1) represent a minimum level of treatment based on technologies that are technologically available and economically achievable, and (2) will result in reasonable progress toward the elimination of the discharge of such pollutants. Such limits are BAT limits.

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[292] CWA § 301(b)(2), 33 U.S.C. § 1311(b)(2) (emphasis added).

CWA § 304(b)(2) requires EPA to take into account the following factors -- referred to in this document as BAT factors -- when it sets BAT limits: the age of the equipment and facilities involved; the manufacturing processes used; the engineering aspects of the application of recommended control technologies, including process changes and in-plant controls; non-water quality environmental impacts, including energy requirements; cost; and such other factors as EPA deems appropriate.[293]

Significantly, the statute sets up a loose framework for EPA's evaluation of the BAT factors in setting BAT limits. It requires not that EPA compare the factors, but rather only that it consider them. Moreover, it does not specify any particular process by which the Agency is to consider the BAT factors, and it does not assign a particular weight to one or more of the factors. Instead, the Act gives EPA discretion to decide how to account for these factors and how much weight to give each factor. In sum, Congress mandated that when EPA considers the BAT factors in setting BAT limits, it be governed solely by a standard of reasonableness. That is, EPA must consider each factor, but it has considerable discretion in identifying and evaluating the more relevant factors and determining the weight to be accorded to each in reaching its ultimate BAT determination. One court has succinctly summarized the standard for measuring EPA's consideration of the BAT factors in setting BAT limits: "[s]o long as the required technology reduces the discharge of pollutants, our inquiry will be limited to whether the Agency considered the cost of technology, along with other statutory factors, and whether its conclusion is reasonable.'"[294]

Technological Availability. "Best available" technology refers not only to the best performing plant in a given industry, but also to any viable transfer technologies (i.e., technology from another industry that could be transferred to the industry in question), including technologies that have been shown to be viable in research even if not yet implemented at a full-scale facility.

EPA must articulate the reasons for its determination that the technology it has identified as BAT is technologically available. Courts have construed the CWA as not requiring EPA to identify the specific technology or technologies a plant must install to meet BAT limits. The Agency merely has to demonstrate that the technology it used to estimate BAT limit costs is a reasonable approximation of the type and cost of technology that must be used to meet the limitations.

The BAT factors that bear on technological availability include the age of the equipment and facility involved. Age by itself is not relevant to the type of treatment technology to be installed to achieve BAT limits. The type of treatment technology to be applied is primarily a function of

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[293] See CWA § 304(b)(2)(B), 33 U.S.C. § 1314(b)(2)(B). See also 40 CFR § 125.3(d)(3).

[294] Ass'n of Pacific Fisheries v. EPA, 615 F.2d at 818.

the pollutants present in a facility's effluent and thus is a function of the type of operation conducted, not the facility's age. However, age does have a bearing on the cost and feasibility of retrofitting existing plants to meet BAT limits. Therefore, to set a BPJ-based BAT limit for thermal discharges from BPS in accordance with CWA §§ 301(b)(2) and 304(b)(2) and 40 C.F.R. § 125.3(d)(3), EPA considered the age of the electric power generation units comprising the facility and their cooling system components as it had a bearing on both the costs of retrofitting one or more those units with the available treatment technologies that the Agency was evaluating as BAT, and the feasibility of such retrofitting.

The factors that EPA must consider in developing BAT limits also include (1) the process or processes employed by the point source category or subcategory or the individual discharger for which the BAT limits are being developed, (2) engineering aspects of the treatment technologies that are being evaluated as BAT, and (3) the changes to the point source process or processes that will result from application of the treatment technology in question. As noted above, EPA has considerable discretion in evaluating the more relevant factors and determining the weight to be accorded to each in reaching its ultimate BAT determination. For example, the Agency can determine that a technology is feasible and will achieve a level of effluent reduction but cannot be designated as BAT in part because its use will result in a significant loss in production. In setting the BPJ-based BAT limit for thermal discharges from BPS, EPA considered (1) the steam electric power generation processes currently employed by BPS; (2) engineering concerns relating to the application of the treatment technologies evaluated as BAT to these processes; and (3) the types of process changes that would result. These factors are related to the age factor insofar as they relate to the feasibility of retrofitting an existing facility to achieve BAT.

Economic Achievability. It is well established that the CWA gives EPA considerable discretion in determining what is economically achievable. CWA § 301(b)(2) neither specifies any special method of evaluating the costs of compliance with BAT limits nor states how those costs should be considered in relation to the other BAT factors. It only directs EPA to consider whether the costs associated with pollutant reduction are "economically achievable." Similarly, CWA § 304(b)(2)(B) only requires EPA to "take into account" the costs of BAT along with the other BAT factors. In sum, the Act does not require EPA to undertake a precise calculation of the costs that would be incurred to comply with BAT limits. Rather, the Agency need make only a reasonable cost estimate in setting those limits.

The courts, including the United States Supreme Court, have consistently read the CWA and its legislative history as indicating Congress's intention that while EPA should consider costs in setting BAT limits, it is not required to perform a cost-benefit analysis or any other kind of balancing test, and that cost is not a factor of primary importance. When a court reviews EPA's BAT determination for a specific point source category or individual discharger, as long as the required technology reduces the discharge of pollutants, the court's inquiry will be limited to whether the Agency considered the cost of technology, along with other statutory factors, and whether its conclusion is reasonable.

Non-Water Quality Environmental Impacts. EPA is not required to consider water quality impacts in setting BAT limits, but it must consider environmental impacts that are not water quality-related. In fact, EPA may determine that a particular technology is technologically available and economically achievable but should not be the basis for BAT limits because of unacceptably high non-water quality environmental impacts.

The CWA gives EPA broad discretion in deciding how to evaluate non-water quality environmental impacts and weigh them against the other BAT factors. The Agency does not need, for example, to demonstrate that the non-water quality environmental impacts of a particular technology are wholly disproportionate to the possible pollution reduction that would result from applying the technology to set BAT limits. Rather, it must apply its discretion and expertise to the relevant information at hand regarding the relative impact of two different environmental harms, and demonstrate on the record that it has considered this information in light of all the BAT factors.

Other Impacts. CWA § 304(b)(2) also allows EPA to take into account such other factors as the Agency deems appropriate when setting BAT limits.

4.6.3 The Technological Availability of the Closed-Cycle Entire Station Option

EPA evaluated a number of cooling system options, including the Closed-Cycle Entire Station option. For example, we assessed and rejected dry cooling technology on the grounds that it costs roughly three times as much as wet mechanical draft cooling tower technology, and as far as we or the permittee could learn, no large existing power plant has been retrofitted to dry cooling. In the Agency's detailed review of the cooling-tower based options we determined to have the most potential to be BAT for reducing thermal discharges from BPS, we evaluated partial closed-cycle cooling options that would involve retrofitting wet mechanical draft cooling tower technology at fewer than all of BPS's generating units (e.g., the Closed-Cycle Unit 3 option). In addition, we assessed the 48-cell Helper Tower option proposed by the permittee.

Finally, EPA carefully evaluated the permittee's Enhanced Multi-Mode option. This option would utilize closed-cycle cooling with wet mechanical draft cooling towers configured in such a way that the towers could be by-passed or could cool water from different units under different circumstances. Again, EPA commends the permittee for developing and proposing the Enhanced Multi-Mode option. Indeed, we believe that the Closed-Cycle Entire Station cooling system should be designed and constructed with the ability to by-pass cooling towers that the Enhanced Multi-Mode option includes. Such cooling tower by-pass capability has been used at other existing power plants. Ultimately, however, EPA determined that the Enhanced Multi-Mode option could not be the "best" available technology because it achieves far lower thermal discharge reductions than the Closed-Cycle Entire Station option.

EPA has concluded that closed-cycle mechanical draft cooling towers are technologically available for retrofitting at Units 1, 2, 3 and 4 at BPS (i.e., the Closed-Cycle Entire Station option). This conclusion is based on the Agency's careful consideration of the BAT factors relevant to technological availability: the age of the plant and its operating systems, the processes the plant uses, and the changes that would be necessary to the plant and its operating systems and processes in order to install and operate closed-cycle mechanical draft cooling towers.

The permittee has contended that retrofitting closed-cycle cooling at BPS would pose design, engineering and construction difficulties because of incompatibility between the Closed-Cycle Entire Station option and the existing station. According to the permittee, the fact that BPS is already built means that any retrofit project there would need to take into account not only the once-through cooling system components that are already in place and in use at the site, but also the other site structures and features that already exist there, and the limited open space available at the site as a result of those structures and features that are already present.

EPA agrees with the permittee that retrofitting the Closed-Cycle Entire Station option at BPS would be complicated because of these considerations. The Agency notes, however, that the permittee has not asserted that such a retrofitting project would be infeasible due to any of these considerations. Moreover, in its research for the CWA § 316(b) Phase II Existing Facility proposed rule, EPA identified several other large power plants that have successfully converted from once-through cooling to closed-cycle mechanical draft cooling towers. These towers have been designed and installed to work effectively in cooling systems using salt or brackish water, as BPS's existing cooling system does. Finally, the permittee itself has confirmed the technological availability of the Closed-Cycle Entire Station option: in the December 2001 USGenNE 316(a) and (b) Demonstration, the permittee presents preliminary design specifications, a site layout and a proposed construction schedule for the Closed-Cycle Entire Station option, and explains in detail both how this closed-cycle mechanical draft cooling tower system would be retrofitted at BPS's four steam-electric generating units and how it would operate once installed.

4.6.4 The Economic Achievability of the Closed-Cycle Entire Station Option

As discussed in detail above, the CWA provides that even minimal environmental impact can be regulated as long as the BAT limits in question are technologically and economically achievable. The courts have agreed that when they review EPA's BAT determination for a particular point source category or individual discharger, "[s]o long as the required technology reduces the discharge of pollutants, [their] inquiry will be limited to whether the Agency considered the cost of technology, along with other statutory factors, and whether its conclusion is reasonable.'"[295]

[295] Ass'n of Pacific Fisheries, 615 F.2d at 818.

Therefore, in setting the BPJ-based BAT limit for thermal discharges from BPS, EPA considered the costs of the various technologies that could be used as BAT at the plant, the economic impact of these costs on the permittee and ratepayers, and the reasonableness of these costs and impacts in light of the CWA's ultimate goal of eliminating the discharge of all pollutants. Based on all these considerations required by CWA §§ 301(b)(2) and 304(b)(2), we have concluded that retrofitting closed-cycle mechanical draft cooling towers at Units 1, 2, 3 and 4 at BPS (i.e., the Closed-Cycle Entire Station option) is economically achievable for the permittee.

Both the permittee and EPA prepared detailed estimates of the potential costs to the permittee of implementing the unit-specific and multi-mode cooling tower-based options under consideration to be BAT for reducing thermal discharges from BPS. Despite the parties' efforts to narrow areas of disagreement, our respective cost estimates vary considerably. Nonetheless, EPA believes its cost estimates are reasonable and appropriate in light of the CWA's ultimate goal of eliminating the discharge of all pollutants.

EPA's cost estimates are reasonably conservative and based on sound, careful evaluation (the Agency's cost analyses having been conducted in conjunction with expert consultants). Capital costs represent the largest source of variation in the estimates developed by EPA and the permittee. In fact, EPA conducted two different, independent analyses to develop capital cost estimates, and both yielded far lower figures than those estimated by the permittee. EPA used the higher of our two independent capital cost estimates in our subsequent analyses.

Apart from capital costs, there were other areas of difference between EPA's and the permittee's cost estimates. These include the magnitude of the efficiency and auxiliary power penalties that the permittee would incur to operate various cooling system options, the length of generating unit outages that would be necessary for cooling tower construction, and the discount rates used in the calculations. Again, EPA believes its analyses and their conclusions are reasonable and appropriate. These factors are discussed in more detail earlier in this document. In the table below, we have set forth certain relevant figures from EPA's and the permittee's respective analyses related to the Closed-Cycle Entire Station option.

Table 4.6-1: Comparison of Selected Permittee and EPA/Abt Cost Scenarios

Technology Option	Permittee 15% Discount Rate Figures (with calculation errors corrected by Abt) (over 20 years)[1]	EPA/Abt Figures (using 11.8 Discount Rate and other independent values) (over 20 years)	EPA/Abt Figures (using 11.8 Discount Rate and other independent values) (over 30 years)
Closed-Cycle Entire Station			
0% plume abatement[2]			
Total After-Tax Cash Flow Cost, Present Value:	Not Calculated	$68.385 Million	$67.975 Million
Annual Equivalent Cost:	Not Calculated	$9.041 Million	$8.314 Million
100% plume abatement[3]			
Total After-Tax Cash Flow Cost, Present Value:	$254.485 Million	$83.269 Million	$85.803 Million
Annual Equivalent Cost:	$40.657 Million	$11.009 Million	$10.494 Million

1 The permittee's figures for the Closed-Cycle Entire Station option reflect its capital costs and its assumptions for generating unit outages for water vapor plume abatement.

2 The Abt/EPA "0% plume abatement" figures reflect no generating unit outages for plume abatement, but do reflect the SAIC-estimated capital costs that were increased to reflect piping and pumping costs to allow the cooling towers to function in multi-mode fashion so that they could be bypassed if necessary to avoid generating unit outages for plume abatement.

3 The Abt/EPA "100% plume abatement" numbers reflect calculations including 100% of the plume abatement effect predicted by the permittee. However, these figures also reflect SAIC's capital cost estimates without the upward adjustment to equip the cooling towers for potential multimode/bypass functioning.

Assuming a twenty-year equipment life, the permittee estimated the Total After-Tax Cash Flow Cost, Present Value costs for the Closed-Cycle Entire Station option to be approximately $254 million, with an equivalent annual cost of approximately $41 million. However, also assuming a twenty-year equipment life, EPA estimated the Total After-Tax Cash Flow Cost, Present Value costs for the Closed-Cycle Entire Station option, assuming no plume abatement outages and increased capital costs to allow for bypass capability of the cooling towers, to be approximately $68 million, with an annual equivalent cost of approximately $9 million. Assuming a thirty-year equipment life, which EPA believes is more likely, the total costs are still approximately $68 million, but the equivalent annual cost drops to $8 million.

In sum, based on the information available to us to date, EPA has concluded that the cost of implementing the Closed-Cycle Entire Station option at BPS is reasonable, and that, therefore, the Closed-Cycle Entire Station option is economically achievable for the permittee. We believe this to be the case whether one considers the EPA costs with the zero percent or the 100 percent plume abatement economic effects scenario (and we believe the zero percent scenario is more likely), as well as whether one considers EPA's cost estimates or the permittee's cost estimates (although we believe EPA's estimates are more reasonable and should be used). Indeed, the permittee has not presented an economic inachievability argument to the regulatory agencies. EPA understands that the expenditures contemplated are significant and will cut into the permittee's profits. Nevertheless, BPS has long been a very profitable plant, and it will remain so after the improvements associated with the Closed-Cycle Entire Station option are installed.

4.6.5 Non-Water Quality Environmental Impacts

EPA considered the various environmental and energy issues that are raised by a proposed conversion from once-through cooling to the Closed-Cycle Entire Station option. We believe that the environmental issues that the permittee has raised in its submissions to the regulatory agencies are either insignificant or can be managed. As discussed in detail above, neither noise, air emissions, aesthetic concerns, salt drift nor any other issue raises a problem that renders modernizing the BPS cooling system by retrofitting wet mechanical draft cooling towers infeasible or inappropriate. Obviously, the facility would need to comply with federal, state and local requirements for noise and air emissions.

4.6.6 Other Impacts

The permittee has raised the issue of whether traffic safety problems could result from cooling tower vapor plumes causing fog or ice affecting Route 195 or the Braga Bridge. The permittee indicates it could alleviate any such problem by instituting periodic generating unit shutdowns, but asserts that such shutdowns would be very expensive.

EPA has examined this issue in depth because it raises the possibility of a public safety concern.

Our research on the vapor plume fog/ice issue at other plants indicates that it is unlikely that cooling tower plumes would create fog or ice that would pose significant traffic safety problems at Route 195 or the Braga Bridge and require generating unit shutdowns. Indeed, the permittee's analysis – about which EPA has many questions and reservations – suggested only a small marginal potential increase in fog or ice over existing background conditions, and this possible increase was well within the range of natural variability in the background conditions. Nevertheless, EPA also believes there are a number of potential ways to deal with any problem that does emerge. These range from coordinating extra safety measures with the Massachusetts Highway Department (MHD) (e.g., deployment of extra fog warning signs, extra road sanding/salting crews, as EPA and the MA DEP have discussed with the MHD), to engineering the cooling towers so that they can be by-passed (i.e., shifted to temporary once-through cooling operations) if necessary to protect traffic safety, to undertaking cooling tower and generating unit shutdowns if absolutely necessary to ensure public safety. However, EPA does not believe the last situation is likely to occur. The permittee could install hybrid (wet/dry) cooling towers to further reduce any threat of vapor plume problems, but the likely extent of the potential problem does not appear to warrant the increased expense of this technology.

4.6.7 Conclusion

In light of its analysis in accordance with CWA §§ 301(b)(2) and 304(b)(2) and 40 C.F.R. § 125.3, and based on Best Professional Judgment (i.e., BPJ) under CWA § 402(a)(1), EPA concludes that the Closed-Cycle Entire Station option is technologically available and economically achievable, and will result in reasonable progress toward the elimination of the discharge of all pollutants. See CWA §§ 301(b)(2)(A), 304(b)(2)(B), 33 U.S.C. §§ 1311(b)(2)(A), 1314(b)(2)(B). EPA therefore concludes that a thermal discharge limitation based on the Closed-Cycle Entire Station option, i.e., an annual heat load discharge limit of 0.8 TBTU with a maximum temperature of 85 °F[296], reflects the Best Available Technology Economically Achievable (i.e., BAT) for reducing thermal discharges from BPS and should be the annual heat load discharge limit for BPS under CWA § 301(b)(2) and in accordance with CWA § 304(b)(2) and 40 C.F.R. § 125.3.

[296] December 2001 USGenNE 316(a) and (b) Demonstration, Vol. IV, App. H, p. 3.3-25.