

**BEFORE THE ADMINISTRATOR
UNITED STATES ENVIRONMENTAL PROTECTION AGENCY**

An Operating Permit for the Koch Industries'
Georgia Pacific Consumer Products LP plant,
Brown County, Wisconsin.

Source I.D. 405032870

Permit No. 405032870-P10

Petition No. V-2011-_____

Proposed by the Wisconsin Department of Natural
Resources on May 23, 2011.

PETITION REQUESTING THAT THE ADMINISTRATOR OBJECT TO ISSUANCE
OF THE PROPOSED TITLE V OPERATING PERMIT FOR THE KOCH
INDUSTRIES' GEORGIA PACIFIC CONSUMER PRODUCTS LP PLANT

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Pursuant to section 502(d)(1) of the Clean Air Act, 42 U.S.C. § 7661a(d)(1), each state must develop and submit to U.S. EPA an operating permit program that meets the requirements of Title V of the Act. EPA granted interim approval of Wisconsin's program, effective April 5, 1995, and final approval effective November 30, 2001. 40 C.F.R. pt. 70, Appx A. Wisconsin purported to apply its program in issuing the renewal permit to the Georgia Pacific Consumer Products plant at issue here. However, the proposed renewal permit contains serious errors that necessitate an objection by the Administrator in response to this Petition.

Pursuant to Clean Air Act § 505(b)(2) and 40 CFR § 70.8(d), the Sierra Club, Clean Water Action Council, and Midwest Environmental Defense Center (together herein as "Petitioners") hereby petition the Administrator ("the Administrator") of the United States Environmental Protection Agency ("U.S. EPA" or "EPA") to object to a proposed Title V Operating Permit for the Koch Industries' Georgia Pacific Consumer Products plant ("GP"), Permit Number 405032870-P10 ("Permit"). The Permit was proposed to U.S. EPA by the Wisconsin Department of Natural Resources ("DNR") more than 45 days ago. A copy of the proposed Permit is attached as Exhibit A.

Petitioners and others provided comments to the DNR on the draft permit and the revised draft permit. A true and accurate copy of Petitioners' comments is attached at Exhibit B. DNR's response to comments is attached as Exhibit C.

This petition is filed within sixty days following the end of U.S. EPA's 45-day review period, as required by Clean Air Act ("CAA") § 505(b)(2).¹ The Administrator must grant or deny this petition within sixty days after it is filed. If the Administrator

¹ DNR proposed the permit to EPA on May 23, 2011. EPA's forty-five (45) comment period expired no early than July 7, 2011. The public's time for petitioning the Administrator extends through, at least, September 5, 2011.

determines that the Permit does not comply with the requirements of the CAA, or fails to include any “applicable requirement,” he must object to issuance of the permit. 42 U.S.C. § 7661b(b); 40 C.F.R. § 70.8(c)(1) (“The [U.S. EPA] Administrator will object to the issuance of any permit determined by the Administrator not to be in compliance with applicable requirements or requirements of this part.”). “Applicable requirements” include, *inter alia*, any provision of the Wisconsin State Implementation Plan (“SIP”), including any term or condition of any preconstruction permit, any standard or requirement under Clean Air Act sections 111, 112, 114(a)(3), or 504, acid rain program requirements. 40 C.F.R. § 70.2.

This petition seeks an objection by the Administrator for three reasons:

- 1) The permit lacks applicable new source review program requirements and Wisconsin DNR applied an erroneous interpretation of the “routine maintenance” exemption to determine that these requirements do not apply.
- 2) The permit lacks applicable new source review and new source performance standard requirements that were triggered through non-exempt fuel switching and Wisconsin DNR improperly deferred addressing this issue.
- 3) The permit lacks applicable requirements ensuring protection of air quality increments, which apply pursuant to the Wisconsin SIP and the Prevention of Significant Deterioration programs, because the Wisconsin DNR misinterprets the applicable regulations defining increment consuming emissions.

I. The Permit Lacks Applicable Requirements That Apply Because The Boilers Have Been Modified.

All major stationary sources, including the GP plant at issue here, are required to apply for Title V operating permits that include emission limitations and other conditions as are necessary to assure compliance with applicable requirements of the Clean Air Act, including the requirements of the applicable State Implementation Plan, the Prevention of

Significant Deterioration, the Nonattainment New Source Review, and the New Source Performance Standard programs. 42 U.S.C. §§ 7661a(a), 7661c(a); 40 C.F.R. § 70.1; *In re Monroe Elec. Gen. Plant, Entergy Louisiana, Inc.*, Petition No. 6-99-2 (Adm’r, June 11, 1999); 57 Fed. Reg. 32,250, 32,250-51 (July 21, 1992). Title V is therefore a main vehicle for ensuring that air quality control requirements are applied to a facility, that the facility complies with the requirements, and that the compliance is monitored and enforceable.

Part C of the Clean Air Act establishes the Prevention of Significant Deterioration (PSD) program of the Clean Air Act. 42 U.S.C. §§ 7470-7479. Pursuant to the PSD program, no major source may be constructed or modified without obtaining a permit. 42 U.S.C. § 7475(a)(1). Additionally, each new or modified facility must comply with emission limits that are “best available control technology” (BACT) and must demonstrate that their emissions do not cause or contribute to a violation of either a national ambient air quality standard (NAAQS) or a limit on incremental air quality degradation known as “increment.” 42 U.S.C. § 7475(a)(3), (4). EPA has promulgated implementing regulations at 40 C.F.R. §§ 51.166 and 52.21. Every facility must comply with these requirements, including through the facility’s Title V permit. 40 C.F.R. § 70.2.

Part D of the Act creates the nonattainment New Source Review program. EPA implements that program through state implementation plan submissions that comply with the requirements of 40 C.F.R. § 51.165 and Appendix S. See Wis. Admin. Code ch. NR 408 (Wisconsin’s nonattainment New Source Review program). Among other requirements, a modified source in a nonattainment area must comply with Lowest

Achievable Emission Rates (LAER) and must satisfy various off-set requirements. 42 U.S.C. § 7502(a)(1), (3).

At relevant times hereto, the facility was located in Brown County, which has been designated as attainment for all pollutants other than sulfur dioxide. Prior to February 26, 1992, Brown County was designated as nonattainment for sulfur dioxide. See http://www.epa.gov/oaqps001/greenbk/anay_wi.html. The portion of Brown County that includes the facility was designated nonattainment for sulfur dioxide in 1981 through February, 1992. http://www.epa.gov/oaqps001/greenbk/phistory_wi.html.

The New Source Performance Standard (NSPS) program in the Act requires modified sources to comply with standards established by EPA pursuant to 42 U.S.C. § 7411. Those standards are promulgated in 40 C.F.R. part 60.

The Permit at issue here contains no BACT or LAER limits for the boilers B25, B26, or B27. Nor does the permit include NSPS standards for those boilers. Similarly, the permit does not subject the plant to off-set requirements for SO₂ for major modifications that occurred while the area in which the plant is located was designated as nonattainment for sulfur dioxide.

A. Petitioners' Public Comments.

Petitioners submitted public comments during the comment period that specifically raised the issue of modifications to the facility's modified boilers, and that the draft permit did not ensure compliance with NSR, PSD and NSPS requirements. *See* Ex. B. Specifically, Petitioners noted that the draft permit contains a table listing the "Installation/Modification Date" for each unit that does not account for numerous modifications made to the units after the dates identified in the table. Ex. B, Comments

at 1. Additionally, Petitioners noted that the permit shield inappropriately extended to the boilers for compliance with the NSPS standards even though Wisconsin DNR did not conduct an investigation to determine whether the boilers have been modified and, therefore, whether additional NSPS provisions apply. *Id.* As Petitioners noted, there have been many modifications—based on public documents and sworn testimony of a former managers—that were not accounted for in DNR’s permit. *Id.* at 1-3. Lastly, the permit comments noted that “because the boilers were modified several times, in numerous ways... PSD is an applicable requirement. DNR must include BACT and other PSD program requirements in the operating permit.” *Id.* at 4.

B. DNR’s Response To Comments

In DNR’s Response to Comments (RTC), it acknowledged Petitioners’ comments and identified a number of projects that had occurred at the facility’s boilers. Ex. C, RTC at 1-7. For all but one of the projects that DNR determined had occurred at the plant, Wisconsin DNR undertook an analysis to determine whether the project was “routine maintenance” and, if not, then whether the project resulted in an emission increase. *Id.* For all but one of the modifications made to the plant, DNR determined that the projects constituted exempt “routine maintenance.” *Id.* For one project—a reheater replacement on Boiler B26—DNR purported to rely on a prior “determination” by the agency regarding “routine maintenance.” While that prior “determination” was not part of a permit decision, nor otherwise subject to public notice and comment, DNR nevertheless refused to address the project based on its past decision. *Id.*

The only project that DNR determined not to be “routine maintenance” was a project that involving replacement of a cyclone burner on Boiler B27. DNR determined

that project was not routine maintenance, but that, notwithstanding a lack of any actual analysis of emissions, that “it is most likely that the replacement did not result in either an increase in hourly emissions, or a significant increase in annual emissions.” Ex. 3, RTC at 3. DNR provides no apparent basis for this determination. *See* Email from Susan Kraj, USEPA, May 10, 2011, 2nd ¶ (noting that DNR’s analysis provides “no emissions data to support” DNR’s assertion that “there was not an increase in emissions,” even though DNR concluded that the purpose of the project was “to restore lost capacity”) (attached as Exhibit D). As set forth below, DNR’s analysis was wrong on both its determinations that projects were not “routine maintenance” and that emissions did not increase—based on the applicable emission increase test—for the cyclone replacement project.

C. EPA Should Correct DNR’s Erroneous Assumption That Because EPA Requested Information From the Facility and Has Not (Yet) Filed An Enforcement Action That EPA Has Made A Conclusion That No Modifications Have Occurred.

DNR asserts that:

It should be noted that EPA requested information on Boilers B25, B26, B27 and B28 through a Section 114 request dated March 6, 2003. Additional information on Boilers B26 and B28 was requested in a Section 114 request dated August 26, 2003. The facility responded to these requests through letters dated April 10, 2003 and May 23, 2003. EPA did not determine that the boilers were subject to NSPS or PSD review as a result of the information submitted at that time.

Ex. C, RTC at 2; *see also id.* at 5 (stating that a 2002 project was inquired into by EPA in 2003 and that “EPC did not determine that Boiler B26 was subject to NSPS or PSD as a result of the information submitted at that time”). Additionally, DNR asserts that “EPA sent the facility a Section 114 request in 2003 which asked for information about

petroleum coke use in B26 and B27” and that “[t]o the Department's knowledge, EPA has not determined that B26 and B27 are subject to NSPS based on the information submitted. The Department will not duplicate EPA's investigation in this regard.” Ex. C, RTC at 7.

DNR appears to believe that if EPA requests information and does not immediately file an enforcement action, that EPA has necessarily reached a final conclusion that New Source Review/PSD and New Source Performance Standards do not apply. This assumption is incorrect. EPA enforcement personnel have limited time and limited resources. The fact that it has not (yet) filed an enforcement case could as easily be attributed to a significant work load, prioritization of other work, a lack of sufficient staff resource to review information, or any other reason other than a final determination of non-applicability. In fact, in a May 12, 2011, email from Susan Kraj, USEPA, to Carol Crawford, WDNR, EPA states: “our enforcement staff told me that they did not make any affirmative statements of compliance... they did not pursue and of the other boilers.” *See* Email from Susan Kraj, USEPA, to Carol Crawford, WDNR (May 12, 2011) (attached as Exhibit E).

D. DNR’s “Routine Maintenance” Determination Is In Error And, Therefore, The Permit At Issue Contains Material Mistakes And Fails To Comply With All Applicable Requirements.

1. Background On “Routine Maintenance Repair And Replacement.”

The Clean Air Act makes the provisions of the PSD program applicable to each newly constructed or modified existing source. 42 U.S.C. § 7475(a), 7479(2)(C). EPA, however, created an exemption to this requirement through a rule, 40 C.F.R. §§

51.166(b)(2)(iii), 52.21(b)(2)(iii)(a)—asserting that broad language of the Act could “encompass the most mundane activities at an industrial facility (even the repair or replacement of a single leaky pipe, or a change in the way that pipe is utilized).” 57 Fed. Reg. 32,314, 32,316 (July 21, 1992)². The “routine maintenance” exemption was never challenged as part of the litigation over EPA’s 1980 rulemaking. *See generally Alabama Power Co. v. Costle*, 636 F.2d 323 (D.C. Cir. 1980) (not addressing any challenges to the “routine maintenance” exemption); *id.* at 361 (noting that EPA’s “de minimis” exemption authority had not been challenged by the parties for situations other than those addressed by the court’s opinion). However, the D.C. Circuit has recently questioned the legality of the Routine Maintenance exemption, stopping short of vacating it because it was not directly challenged and therefore not within the Court’s jurisdiction at the time. *New York*, 443 F.3d 880, 888 (D.C. Cir. 2006) (*citing Shays v. FEC*, 414 F.3d 76, 113-14).

The *New York* court’s reasoning questions whether the “routine maintenance” exemption is legal at all. To the extent it is lawful, it can only be lawful if it is exempts only truly *de minimis* modifications. *Ala. Power*, 636 F.2d at 360-61, 400; *New York*, 443 F.3d at 888; *In re Tenn. Valley Auth.*, 9 E.A.D. 357, 392-93 (EAB 2000). Therefore, the exemption must be very narrowly interpreted and applied. *See Kimel v. Fla. Bd. of Regents*, 528 U.S. 62, 87 (U.S. 2000); *Rugiero v. United States DOJ*, 257 F.3d 534, 543 (6th Cir. 2001); *Shays v. FEC*, 414 F.3d 76, 113-14 (D.C. Cir. 2005) (“situations covered by a *de minimis* exemption must be truly *de minimis*.”). EPA’s longstanding interpretation of the definition of modifications that trigger PSD has been very broad “to cover virtually any significant alteration to an existing plant and to interpret the exclusion

² This statement, if taken alone, actual overstates the issue. Simply fixing a leaky pipe would not automatically be a major modification, subject to NSR requirements. An emission increase must still occur (i.e., be estimated based on applicable emission increase tests applied prior to the project).

related to routine maintenance, repair and replacement narrowly.” Ltr. from Doug Cole, EPA to Alan Newman, Wash. Dept. Ecology (Nov. 5, 2001); *see also In re Tenn. Valley Auth.*, Petition No. IV-2010-1, Order Responding to Petition to Object to Title V Permit at 7 (Adm’r, May 2, 2011) (“The plain language of [42 U.S.C. §§ 7411(a)(4), 7475(a), and 7479(2)(C) and 40 C.F.R. § 52.21(b)(2)(i)] indicates their sweeping scope. Both the CAA and its implementing regulations define “modification” as including any physical or operational change. In light of that breadth, any regulatory exemption from the statutory and regulatory requirements should be interpreted in a limited way.” (internal citations omitted)) (hereinafter “TVA T5-Order”)³.

Courts have similarly interpreted the “Routine Maintenance” exception narrowly. *See e.g., U.S. v. So. Indiana Gas & Elec. Co.*, 245 F.Supp. 2d 994, 1019 (S.D.Ind. 2003) (exemptions from the definition of “modification”—including routine maintenance—are “very narrow”). Courts have identified three hallmarks of the Routine Maintenance exemption:

First, the exemption applies to a *narrow range of activities*, in keeping with the EPA’s limited authority to exempt activities from the [CAA]. Second, the exemption applies only to activities that are *routine for a generating unit*. The exemption does not turn on whether the activity is prevalent within the industry as a whole. Third, *no activity is categorically exempt*. EPA examines each activity on a case-by-case basis, looking at the nature and extent, purpose, frequency, and cost of the activity.

United States v. Ohio Edison, 276 F. Supp. 2d 829, 834 (S.D. Ohio 2003) (*quoting SIGECO*, 245 F.Supp. 2d at 1008) (emphasis added, original emphasis omitted); *see also Sierra Club v. Morgan*, 2007 U.S. Dist. LEXIS 82760, at *33-34 (W.D. Wis. 2007).

³ Available at http://www.epa.gov/region7/air/title5/petitiondb/petitions/tva_paradise_response2010.pdf

Whether a project falls within the narrow Routine Maintenance exemption depends on a four-factor assessment, focusing on: (1) the nature and extent of the project; (2) the project's purpose; (3) the frequency of the project; and (4) the project's cost. *See WEPCO*, 893 F.2d at 909-11; *SIGECO*, 245 F.Supp. 2d at 1008; *United States v. Ohio Edison*, 276 F. Supp. 2d 829, 855 (S.D. Ohio 2003); *United States v. Cinergy Corp.*, 495 F. Supp. 2d 909, 930 (S.D. Ind. 2007); Memorandum from Don R. Clay, Acting Assistant Administrator for Air and Radiation, to David A. Kee, Air and Radiation Division, Region V, at 3 (“Clay Memo”)⁴. The EPA has applied this test to plants in Michigan. Letter from Francis X. Lyons, Regional Administrator, EPA Region V, to Henry Nickel (May 23, 2000) (“Detroit Edison”)⁵.

The burden is on the facility to demonstrate that it qualifies for RMRR. (CITE—including TVA EAB?). Therefore, if information about a project is missing because the facility failed to keep records in support of its RMRR claims, it cannot claim a benefit from the lack of such information. Ex. D, Email from Susan Kraj, USEPA, to Carol Crawford, WDNR (May 10, 2011).

i. Nature and Extent

Under the first factor-- nature and extent—the relevant question is whether major components are being modified or replaced, including whether the parts or “of considerable size, function, or importance to the operation of the facility.” TVA T5-Order at 10; Memo from Steve Dunn, WDNR, to UW-Charter Street Title V Renewal File at p. 3 (May 8, 2007) (“Charter St. Memo”) (attached as Exhibit F). Thus, a project that replaces of most or all of a major component of the source is not routine. Detroit

⁴ Available at <http://www.epa.gov/region7/air/nsr/nsrmemos/wpc02.pdf>

⁵ Available at <http://www.epa.gov/region7/air/nsr/nsrmemos/detedisn.pdf>

Edison at 10 (Explaining that the analysis examines “[w]hether major components of a facility are being modified or replaced; specifically, whether the units are of considerable size, function, or importance to the operation of the facility, considering the type of industry involved.”).

The use of outside contractors, use of new materials or equipment, and duration⁶ of the project (possibly including a shutdown of the unit) each indicates a non-routine project. *Id.*; *Cinergy*, 495 F. Supp. 2d at 933-34; TVA T5-Order at 11. Similarly, projects that require the approval of upper-level management are considered non-routine. *Ohio Edison* at 859 (finding a project to be non-routine where approval was “handled by [the utility’s] central office” and not the plant manager); *Cinergy*, 495 F. Supp. 2d at 939.

EPA has interpreted the “routine maintenance” exemption in the context of replacing boiler tubes (which includes every project at issue in this Petition) by contrasting the replacement of a single, or up to a couple, worn or damaged tubes on an as-needed basis, which may be routine maintenance, with those projects that are categorically different, and non-routine, that involve replacing all of the tubes in a component section of a boiler. *See* Letter from Robert B. Miller, EPA, to Steven Dunn, Wisconsin DNR (Jan. 29, 2003)⁷; Letter from Doug Cole, EPA, to Alan Newman, Washington Dept. of Ecology at 3 (Nov. 5, 2001) (finding that replacement of a component, rather than a few tubes, does not support a Routine Maintenance

⁶ Routine projects to repair boiler tubes typically “take no more than a day or two.” See Ltr. from Robert Miller to Steven Dunn at 2 (P.H. Glatfelter).

⁷ Available at <http://www.epa.gov/region7/air/nsr/nsrmemos/20030129.pdf>

determination)⁸; Letter from Gregg M. Worley, EPA, to Barry R. Stephens, Tenn. Dept. of Env't. and Conservation at 4 (September 14, 2001) (same)⁹.

EPA has also noted that a change that requires the emission source to be shut down for the work, rather than performing the work during full functioning, is not routine. *See* TVA T5-Order at 11. Even projects that involve a shutdown of “several days to accomplish” are not routine. *See* Ltr. from Winston Smith, USEPA, to James P. Johnson, Georgia Env'tl. Protection Division at 3 (Jan. 28, 2002) (changes to boiler after 17 years not frequent and not routine)¹⁰. And, obviously, a project that adds parts to existing equipment that did not previously exist is not routine. TVA T5-Order at 18.

ii. Purpose

Under the second factor—purpose—the overall objective of the project is compared to the purpose of a truly routine maintenance task. The purpose of truly routine maintenance is to fix a piece of equipment on an as-needed basis, with no expectation that the fix will improve the plant’s operations by, for example, reducing the frequency of future tube ruptures and forced outages. *TVA*, 9 E.A.D. at 406, 485; *Morgan*, 2007 U.S. Dist. LEXIS 82760, at *36. By contrast, projects that are expected to make a unit more reliable, increase unit availability by avoiding future tube failures clearly go beyond “mere maintenance” and fall well outside the Routine Maintenance exemption. *Ohio Edison*, 276 F. Supp. 2d at 860; *see also WEPCO*, 893 F.2d at 911-12; *Morgan*, 2007 U.S. Dist. LEXIS 82760 at *38-3, *41 (finding that a project intended “to increase the reliability and availability of the boilers and to . . . allow the boilers . . . to

⁸ Available at <http://www.epa.gov/region7/air/nsr/nsrmemos/20011105.pdf>

⁹ Available at <http://www.epa.gov/region7/air/nsr/nsrmemos/pca2001.pdf>

¹⁰ Available at <http://www.epa.gov/region7/air/nsr/nsrmemos/20020128.pdf>

remain in operation” was not routine maintenance); *Cinergy* at 935 (declining to extend the Routine Maintenance exemption to a project that resulted in “significantly improved operating efficiency with less potential outages anticipated.”) (internal quotations omitted); TVA T5-Order at 11; Ex. F, Charter St. Memo at 3 (noting that projects allowing “enhanced operation”, including “increased utilization” are not routine). Therefore, Wisconsin DNR has previously determined that the purpose of a project to replace parts that were “worn out,” or to address the cause of frequent tube leaks and thereby avert future leaks, is not routine. Ex. F, Charter St. Memo at 3-4. Even where projects may be routine “if performed regularly as part of standard maintenance procedure while the plant was functioning or in full working order,” were nevertheless not routine if “performed as part of an exhaustive rehabilitation project.” TVA T5-Order at 10 (internal quotations omitted).

iii. Frequency

Under the third factor—frequency—the analysis looks to how often the same project occurs at the unit in question or a typical unit’s life. TVA T5-Order at 11 (“Whether the change is performed frequently in a typical unit’s life.”); Ex. F, Charter St. Memo at 3. The Routine Maintenance exemption applies only to projects that occur in the ordinary course of operations at the unit in question, or at most, in a typical unit’s life. Routine maintenance projects are “regular, customary, or standard undertaking[s] for the purpose of maintaining *the plant* in its present condition.” Clay Memo at 3-4 (emphasis added). EPA has indicated that only those projects that “occur annually, or on a[] regular basis” at a particular unit are routine. See Letter from Doug Cole, EPA, to Alan Newman, *supra* at 3.

Simply stated, projects that “normally occur once or twice during *a unit’s expected life cycle*” are not routine. *WEPCO*, 893 F.2d at 912 (emphasis added); *Detroit Edison* at 20-21; *TVA*, 9 E.A.D. at 407 (“Although TVA introduced evidence that it and others in the industry had made similar replacements at other facilities, the evidence did not show that these replacements were other than uncommon in the lifetime of the unit.”); Letter from Robert Miller to Steve Dunn, *supra* at p. 2 (“Moreover, the infrequency of such replacement *at this boiler* supports our understanding that complete boiler tube replacements are not performed on a frequent basis.” (emphasis added)); Letter from Winston A. Smith, EPA, to James P. Johnson, Georgia Env’tl. Protection Dept. (finding that frequency did not support a finding of routine where “the previous owner of the mill never performed the same changes *at the No. 3 Recovery Boiler* during its entire 17-year operating history.” (emphasis added)); Letter from Doug Cole, EPA, to Alan Newman, *supra* (finding a project not routine because “EPA is not aware of [the unit at issue] undergoing such an extensive boiler tube replacement project since it started up . . . more than twenty years ago”); Letter from Gregg M. Worley, EPA, to Barry R. Stephens, Tenn. Dept. of Env’t. and Conservation (finding a project not routine where it has only occurred once in the “entire 40-year operating history” of the unit)¹¹. Although EPA has recognized that the frequency of a type of project in the industry as a whole may provide some context for the Routine Maintenance analysis, *see, e.g., TVA*, 9 E.A.D. at 394, the relevant inquiry is frequency at a “typical” (i.e., singular) unit. *TVA T5-Order* at 11; *Clay Memo* at 5 (looking to frequency at the units at issue). EPA has never interpreted

¹¹ Available at <http://www.epa.gov/region7/air/nsr/nsrmemos/pca2001.pdf>

this as determining Routine Maintenance based on the prevalence of a project generally in the source category.

The majority of courts that have applied the Routine Maintenance analysis has also found that the touchstone for the frequency factor is whether the project is routine for the particular facility at issue. In *SIGECO*, for example, the District Court agreed with EPA's interpretation that the Routine Maintenance exemption "applies only to activities that are routine for a generating unit . . . [not] the industry as a whole." 245 F.Supp.2d at 1008. *See also Ohio Edison*, 276 F. Supp. 2d at 861 (concluding that an "industry-wide standard" as to what is routine would "*render the exemption meaningless*"); *Morgan*, 2007 U.S. Dist. LEXIS 82760, at *36-37.

Courts looking to occurrences in the industry—detached from any context of how many units are in the industry and over how many years of operation project occur-- are in the clear minority, and fail to give weight to the Act's plain language or deference to EPA's longstanding interpretation of its own regulation. *See, e.g., Nat'l Parks Conservation Ass'n v. TVA*, 2010 U.S. Dist. LEXIS 31682, at *49 (E.D. Tenn. March 31, 2010) (*citing United States v. E. Ky. Power Coop., Inc.*, 498 F.Supp.2d 976, 993-94 (E.D. Ky 2007)). If this minority interpretation of the Routine Maintenance exception was applied, it would drag the exception out of the narrow category of exemptions allowed by the *de minimis* doctrine, making the rule itself unlawful. *See New York*, 443 F.3d at 883-84, 888; *Shays*, 414 F.3d at 113-14. It would also turn the Act on its head, exempting virtually all existing facilities from the PSD program by granting them "indefinite immunity" from its pollution control requirements - the opposite of what Congress

intended. *WEPCO*, 893 F.2d at 909; *See also New York*, 443 F.3d at 888; *In re Tenn. Valley Auth.*, 9 E.A.D. at 410-11.

iv. Cost

Under the fourth factor-- cost--numerous courts and EPA have found the method of accounting for the project central to the analysis: routine maintenance projects are certain to be treated as ordinary expenditures under a source's annual operating budget, whereas non-routine projects are approved separately from the annual operating budget and are usually capitalized. *Cinergy* at 936-37; *Ohio Edison* at 860 ("A straightforward and logical construction of the term "maintenance," let alone "routine maintenance," would exclude from its scope any amounts defined as capital expenditures"); *Morgan*, 2007 U.S. Dist. LEXIS 82760, at *42; *Detroit Edison* at 11; *TVA T5-Order* at 11.

Courts and EPA have found projects that cost in the tens to hundreds of thousands of dollars or more to be non-routine. *See e.g., Morgan*, 2007 U.S. Dist. LEXIS 82760, at *39 (finding that a \$ 77,000 cost was not routine), *id.* at *44 (same for a \$90,700 project); *Cinergy*, 495 F.Supp.2d at 938, 942-43, 947 (finding a projects costing \$665,000 to \$1,490,800 not to be routine); Letter from Robert B. Miller, EPA, to Steven Dunn, Wisconsin DNR (finding a project costing \$50,000 not to be routine).

2. EPA's Preliminary Response to WDNR's Routine Maintenance Analysis.

WDNR's Response to Comments was shared with USEPA just weeks before WDNR finalized it. USEPA preliminarily reviewed WDNR's draft Routine Maintenance determinations and provided the following response:

Regarding the RMRR determinations you did in your May 5, 2010, response, it was noted that some of the projects

occurred over 25 years ago and that in some cases the facility no longer has records. These types of projects can be difficult to analyze after the fact...

Note that the burden is on the facility to be able to provide all data and records to demonstrate there was not a modification or a significant increase in emissions....

In addition, there are numerous examples where EPA has found similar tube replacement projects to be non-routine, including where Region 5 has determined that replacement of a superheater bundle should increase the reliability of the boiler and most likely will extend the life of the boiler. (See several examples included below). You concluded that the cyclone burner replacement on B27 was not RMRR, but that the superheater replacement projects on Boiler 26 and 27, and the waterwall replacements on Boilers 25 and 27 were RMRR. I do not see a significant difference in the data and analysis between the project that was not considered RMRR and the four that were.

However, these determinations are made on a case by case basis. (Is it possible to summarize or explain how you distinguished the four you concluded were RMRR from the one that you concluded was not, or if there was a prevailing factor?)

...

Examples:

- 1) A tube replacement project at PH Gladfelter in WI, which entailed replacing all of the steam tubes in the 180 MMBtu/hr boiler at a cost of \$450,000, and took about 25 days.
- 2) A project at the Willamette Pulp and Paper Mill in Region 4, (while the project type differs from what is going on at Georgia Pacific), the changes to the boiler after 17 years of operation were found to be infrequent and non-routine, as well as found to restore lost capacity.
- 3) Superheater tube replacements, as well as other major boiler components were also found to be non-routine major modifications under the Ohio Edison Decision. All of the projects involved replacement of major components which had never before been replaced on the particular units. As a result, the projects were found to be not routine. In addition, the replacement projects predicted a prevention of tube failures. See EPA v. Ohio Edison, where the court ultimately concluded that the 11 projects were not of the type that could be considered routine...

Ex. D, Email from Susan Kraj, USEPA, to Carol Crawford, WDNR, May 10, 2011.

Notably, WDNR ignored USEPA's input, does not appear to have considered any of the determinations referenced by USEPA, and came to conclusions very different than USEPA's prior determinations and court cases.

3. The Projects At Issue Here Do Not Quality As "Routine Maintenance"¹²

a. DNR Misapplied Some Factors But Correctly Determined That The Cyclone Burner Replacement on Boiler B27 in 1984 Did Not Constitute Routine Maintenance.

Petitioners note that DNR concluded that the 1984 replacement of a cyclone burner on Boiler B27 in 1984 did not constitute routine maintenance. RTC at 3. While this is a correct conclusion, DNR's analysis as to some of the four factors is clearly in error. For example, under the "Nature and Extent" factor, DNR asserts in the Response to Comments that "[t]he fact that the burner was replaced with one of the same or similar size and specifications, serving an identical function, argues in favor of it being considered RMRR." Ex. C, RTC at 3. There is no basis for this assertion provided by DNR and it conflicts with the long-standing interpretations by EPA. As noted above, the relevant inquiry is not whether the replacement parts are of a *similar* size or design, but whether they constitute major components and whether they are "of considerable size, function, or importance to the operation of the facility." TVA T5-Order at 10; Detroit

¹² Petitioners requested documents from U.S. EPA Region 5 in preparation for this Petition. On July 19, 2011, after the deadline for EPA to respond pursuant to the Freedom of Information Act, and contrary to prior representations that EPA would provide all responsive documents, EPA partially denied the request and withheld various documents. Petitioners believe that EPA has improperly withheld documents and will pursue the relief provided under the Freedom of Information Act. To the extent EPA provides the withheld documents in the future, Petitioners reserve the right to supplement this petition with those documents, as necessary.

Edison at 10. Here, the cyclone burner replacement project involved replacing a huge component that is central to the boiler's operation.

DNR also failed to analyze the other relevant facts for the "nature and extent factor," such as the use of outside contractors and approval by upper level personnel at the facility. Therefore, the only facts in the record, and reviewed by DNR, weigh against a finding of "routine" on the nature and extent factor-- contrary to DNR's comments.

On the "Purpose" factor, DNR appears to imply that a purpose of replacing components that had deteriorated over a long period, to restore the unit to an improved condition compared to its condition prior to the project, is consistent with "routine maintenance," and that any project is "routine maintenance" as long as it does not increase operating rates. Ex. C, RTC at 3. To the extent that this was DNR's interpretation, it has no basis. The purpose of boiler tube and cyclone routine maintenance is to fix an immediate problem and return the unit to service with no intent or anticipation of improved unit condition over the longer term. TVA T5-Order at 11; TVA, 9 E.A.D. at 406, 485; *Morgan*, 2007 U.S. Dist. LEXIS 82760, at *36; *Ohio Edison*, 276 F. Supp. 2d at 860; *see also WEPCO*, 893 F.2d at 911-12. Other purposes are not routine.

It is certainly not true that all maintenance is routine as long as it does not increase the rated operating capacity. In fact, EPA has determined projects' purposes to be non-routine even where the purpose was "not to increase operating capacity." *See* Letter from Doug Cole, EPA, to Alan Newman, *supra* at 4. Here, the fact that the project was "intended to *prevent possible future downtime* or failure associated with the cyclone

burner,” Ex. C, RTC at 3, indicates that the purpose was beyond mere routine maintenance.

Lastly, on the “cost” factor, DNR compares the project cost to an inflated “annual” operations and maintenance budget *for the entire power plant*. The annual cost that DNR uses is based on an average from 2004 to 2010 for the entire plant. *See* Ex. C, RTC at 2. This annual maintenance cost comparison is inflated for at least two reasons. First, the annual budget cited by DNR covers the entire power plant, which contains six boilers. DNR uses the value to compare to a single project on a single boiler. This type of comparison would prejudice plants that have only a single boiler because their total annual maintenance costs would be proportionately lower and, thus, any comparison of a project to annual costs would appear higher higher. In contrast, where a facility—like the one at issue here—contains many boilers, very large and expensive projects can occur to a boiler without appearing as large when compared to the cost to maintain many boilers.

A more reasonable comparison is to compare the project cost to that unit’s share of annual costs. The project here cost \$378,571 (when converted to common year dollars based on CPI). Ex. C, RTC at 3. This is higher than the unit’s proportionate share of the plant-wide maintenance budget of \$1,988,000 ($\$1,988,000 / 6 \text{ boilers} = \$331,333 \text{ per boiler}$). Ex. C, RTC at 2. Therefore, while DNR contends that the project cost was “only 19% of the average 2004-2010 power plant maintenance costs,” the cost is actually much more significant—representing more than 114% of the boiler’s proportionate annual operating and maintenance costs.¹³

¹³ Note that the permit record also indicates that the company represents the annual maintenance cost of one boiler—boiler 6—to be \$500,000 per year in 2001. *See* Ltr. from Robert A. Bermke, GP, to Steven Dunn, WDNR (June 3, 2002).

The DNR cost comparison is also inflated because DNR uses the maintenance budgets from 2004 to 2010, but fails to recognize that boiler 9 was added to the plant in 1995—after the project here. The 2004-2010 maintenance budgets include maintenance for boiler 9, which did not exist when the project here occurred and, therefore, DNR’s assumption that budgets did not change between the year of the project (1984) and the years after boiler 9 was added (1995) is unreasonable.

It is also notable that DNR has no consistent approach to making conclusions based on conflicting findings on the four “routine maintenance” criteria. While DNR found (erroneously) that two factors weighed in favor of a “routine maintenance” finding (nature and purpose), one weighed against (frequency), and another was inconclusive (cost), it deemed the B27 cyclone burner replacement project was non-routine. Ex. C, RTC at 3. However, for other projects, such as the waterwall project on Boiler B26, DNR determined a similar break-down of the four factors, yet concluded that the project was “routine.” DNR offers no explanation for why purportedly conflicting conclusions on the four factors leads to a finding of non-routine for one project, yet a finding of routine for another. Conflicting conclusions on the four factors must be resolved against a finding of routine maintenance in light of the extremely narrow scope of the exemption and the fact that the burden lies with the facility to show that it qualifies. *Kimel v. Fla. Bd. of Regents*, 528 U.S. 62, 87 (2000) (regulatory exemption from statute must be narrowly interpreted); *U.S. v. First City Nat’l Bank of Houston*, 386 U.S. 361, 366 (1967) (explaining the “general rule where one claims the benefit of an exception to the prohibition of a statute” carries the burden of proof with respect to that exception); *Shays v. FEC*, 414 F.3d 76, 113-14 (D.C. Cir. 2005) (“situations covered by a *de minimis*

exemption must be truly *de minimis*.”); *Sierra Club v. Duke Energy Indiana*, Case No. 1:08-cv-437-SEB-TAB, 2010 U.S. Dist. LEXIS 32194 (S.D. Ind. March 30, 2010); *United States v. Cinergy Corp.*, 495 F. Supp. 2d 909, 931 (S.D. Ind. 2007) (“it ultimately would be [the facility’s] burden at trial to show that its activities are exempt from CAA compliance.”); *Commonwealth v. Allegheny Energy, Inc.*, 2008 U.S. Dist. LEXIS 97391 (W.D. Pa. Sept. 2, 2008) (“The party claiming the benefit of the RMRR exemption bears the burden of proving its applicability.”); *Sierra Club v. Morgan*, 2007 U.S. Dist. LEXIS 82760, *35 (W.D. Wis. Nov. 7, 2007) (“Because defendants are claiming the benefit of the RMRR exemption the burden falls on the defendants’ to show that the projects are exempt from [the Clean Air Act] compliance.”); *United States v. E. Ky. Power Coop, Inc.*, 498 F. Supp. 2d 976, 995 (E.K. Ky. 2007) (“the burden shifts to [defendant] to prove that its activities are exempt from the definition of ‘modification’ because they were routine.”); *United States v. Ohio Edison Co.*, 276 F. Supp. 2d 829, 856 (S.D. Ohio 2003) (“the party claiming the benefit of an exemption to compliance with a statute bears the burden of proof as to the exemption.”); *see also WEPCO*, 893 F.2d at 909 (warning that the Routine Maintenance exemption cannot be interpreted to “open vistas of indefinite immunity from the provisions of ... PSD”); *Alabama Power Co. v. Costle*, 636 F.2d 323, 360-61, 400 (D.C.Cir. 1979); *New York*, 443 F.3d at 883-84, 888; *In re Tenn. Valley Auth.*, 9 E.A.D. 357, 410-11 (rejecting an interpretation of Routine Maintenance that would “constitute ‘perpetual immunity’ for existing plants[.]”), *appeal dismissed for lack of jurisdiction in TVA v. Whitman*, 336 F.3d 1236 (11th Cir. 2003).

b. The Superheater Replacement Projects on Boilers B26 (1981) and B27 (1988) Where Clearly Not Routine Maintenance.

The Georgia Pacific facility replaced the superheater—meaning all of the superheater tubes in the tube bank-- in Boiler B26 in 1981 and in Boiler B27 in 1988. *See* Letter from Kelly Wolff, Georgia Pacific, to Carol Crawford, WDNR at 3 (Sept. 23, 2010) (“GP 9/23/10 Ltr.”) (attached as Exhibit G). These were not “routine” under any of the four factors.

Nature and Extent: DNR makes no findings on the nature and extent, other than that the replacement on B27 required a shutdown of approximately two weeks (4/17/88-4/20/88). Ex. C, RTC at 4. DNR utterly fails to address the relevant facts that superheater replacement projects: (1) involve replacing an entire component; (2) which is of considerable size; (3) requires a boiler outage; and (4) is important to the operation of the facility. *See* TVA T5 Order at 10-11; Detroit Edison at 10; Ex. F, Charter St. Memo at 3; *see also* Gregg M. Worley, EPA, to Barry R. Stephens, *supra* at 3 (finding a project non-routine and noting that a complete retubing of a component “differs from the more typical maintenance activities that are performed annually in that it involves complete replacement of all the tubes in a major component of a boiler, as opposed to replacement of just a few worn or damages tubes.”). These facts weigh heavily against a finding of “routine.” In fact, DNR has found other superheater replacements to not constitute routine maintenance where the nature and extent was the same as these project: replacement of all superheater tubes without changing the capacity of the boiler. *See* Ltr. from Steven Dunn to Neil Howell (August 13, 2004) (attached as Exhibit H).

DNR also makes no findings on the other relevant facts, such as whether outside contractors were used and whether upper level employees were involved in planning or approving the project. However, it is hard to comprehend that this type of project did not involve both outside contractors and management personnel. These facts would also weigh against routine maintenance.

Purpose: As with the cyclone burner, above, DNR implies that a project is routine as long as it does not increase capacity or as long as the facility does not concede that the purpose was “life extension.” Ex. C, RTC at 4. There is no basis for this interpretation. In fact, it conflicts with prior Wisconsin DNR determinations that found projects to not constitute routine maintenance where the purpose was to address underlying problems and thereby allow increased use of the boiler without changing the rated capacity. *See* Ex. H, Ltr. S. Dunn to N. Howell at 1 (finding project at a boiler to not be routine maintenance where the purpose was to address the root cause of an ongoing problem); Ex. F, Charter Street Analysis at 3-4 (finding a project with a purpose of “replac[ing] steam tubes which were wholly worn out” and that “were reported to have experienced multiple failures” as non routine).

The facts here clearly indicate a non-routine purpose. The company acknowledges that its internal documentation shows that the purpose of the B27 project was to address deterioration of the tubes, which had resulted in “a considerable number of leaks.” *See* Ex. G, GP 9/23/10 Ltr. at 3. Because the purpose was not merely to fix a tube or a few tubes on an as-needed basis, but rather, to address a fundamental problem with the boiler to address a series of repeated tube failures (especially of the type that typically require a boiler outage), the purpose was well beyond mere “routine

maintenance.” TVA T5 Order at 11; *TVA*, 9 E.A.D. at 406, 485; *Morgan*, 2007 U.S. Dist. LEXIS 82760, at *36, *41; *Cinergy* at 935 (declining to extend the Routine Maintenance exemption to a project that resulted in "significantly improved operating efficiency with less potential outages anticipated.") (internal quotations omitted).

Frequency: There is no dispute that the superheater replacements occurred only once at each boiler. Ex. C, RTC at 4; Ex. G, GP 9/23/10 Ltr. at 3. This once-in-the-life-of-a-unit frequency is clearly not indicative of “routine” maintenance. *WEPCO*, 893 F.2d at 912 (projects that “normally occur once or twice during a unit’s expected life cycle” are not routine).¹⁴ Here, the project occurred once each at two different unit—a frequency of one time per unit. Clearly, this is not routine.

DNR’s analysis suggests that because this type of project has occurred once each at two different boilers, that it is therefore “routine.” RTC at 4 (noting that the superheater was replaced once at unit B26 and once on unit B27 and “[t]hus for this facility, replacement of secondary superheater tubes after nineteen years of boiler operation could be viewed as routine.”). DNR’s basis for this assertion is unclear, but it is inconsistent with the Clean Air Act. EPA has previously determined that projects involving the replacement of entire components after 20 years of operation are not routine. *See* Ltr. from Doug Cole, EPA, to Alan Newman, Washington Dept. of Ecology,

¹⁴ As noted elsewhere in this Petition, the “frequency” factor relates to how often a specific project recurs at the unit in question. TVA T5 Order at 11; *see also* Letter from Robert B. Miller, EPA, to Steve Dunn, *supra* at 2 (Jan. 29, 2003) (finding that a tube replacement project is not Routine Maintenance because, inter alia, “this would be the first time in the 35 year life of *the boiler* where all the tubes would be replaced. Moreover, the infrequency of such replacement *at this boiler* supports our understanding that complete boiler tube replacements are not performed on a frequent basis.”) (emphasis added); Letter from Winston A. Smith, EPA, to James P. Johnson, Georgia Env’tl. Protection Dept. (finding that frequency did not support a finding of Routine for a project that had not previously occurred in the unit’s “entire 17-year operating history”); Letter from Doug Cole, EPA, to Alan Newman, *supra* at 4 (finding a project non-routine where it had not previously occurred in the unit’s 20-year life); Letter from Gregg M. Worley, EPA, to Barry R. Stephens (finding a project non-routine where it had not previously been done at the unit).

supra at 4. Moreover, the fact that one of the boilers was “only” 19 years old when the replacement occurred does not indicate a “routine” frequency. *Id.* (project at seventeen year old boiler still not routine); Ltr. from Winston Smith, USEPA, to James P. Johnson, Georgia Env'tl. Protection Division at 4 (Jan. 28, 2002) (changes to boiler after 17 years not frequent and not routine)¹⁵.

Moreover, DNR ignores the obvious implication that an even that happened twice at the plant (once each at two different boilers), over 204 years of boiler life¹⁶, is a frequency of once every 102 boiler-years. This is hardly a “frequent” or “routine” occurrence.

Cost: The superheater replacement on Boiler B26 cost \$171,506.40 (or \$188,675 in common year CPI dollars in DNR’s analysis). RTC at 4. DNR does not know whether the project was capitalized. *Id.* The superheater replacement on Boiler B27 in 1988 cost \$187,900 (or \$158,833 in common year dollars in DNR’s analysis). RTC at 5. The Boiler B27 superheater replacement was capitalized, which DNR notes “argues against it being considered routine maintenance, repair and replacement.” *Id.*; see also Ex I, Table 3 (listing “capital” projects). As with the other projects, DNR conflates the total cost to maintain six to seven boilers at the plant with the cost of individual maintenance projects on one boiler. DNR asserts that the superheater replacement projects represent 8 and 9 percent of the annual operating and maintenance budget for the whole plant. *Id.* at 4, 5. This ignores the fact that the projects likely cost significantly more than any typical repairs to the superheaters, were likely budgeted specifically

¹⁵ Available at <http://www.epa.gov/region7/air/nsr/nsrmemos/20020128.pdf>

¹⁶ Boiler B25 is 61 years old, Boiler B26 is 49 years old, Boiler B27 is 42 years old, Boiler B28 is 36 years old, and Boiler B29 is 16 years old. See Preliminary Determination at p. 3 (installation years).

(rather than being paid for through the general maintenance expense account) and represents a large percentage of boiler B26's annual maintenance cost (i.e., the boiler's proportionate share of the plant-wide maintenance budget).

Conclusion: The superheater projects involved replacing entire significant components and required a boiler outage to complete. The purpose was to address long-term problems with the boilers and thereby improve the reliability of the boilers. The projects were very infrequent—occurring only once in the life of either boiler. The cost was also significant, compared to either the boilers' proportionate share of annual maintenance costs or to the typical cost of recurring maintenance tasks for the superheaters. The superheater replacements were clearly not routine maintenance.

c. The Generating Bank Replacement on Boiler B26 (2002) Was Not Routine Maintenance.

DNR refused to address the Boiler B26 Generating Bank Project because, it asserts, the company previously asserted and the DNR previously “concurred” that this project was exempt. Ex. C, RTC at 5. The so-called “concurrence from DNR,” however, was a single sentence email that contained no analysis. *See* Email from S. Dunn, WDNR, to Robert Bermke, GP (July 16, 2002). It was not part of a permitting action. It did not involve public notice or comment. And, it was not accompanied by the typical indicia of a considered and official agency position. Moreover, the EPA has previously rejected similar attempts by Wisconsin DNR to make informal PSD non-applicability assertions in private correspondence with a facility and then refuse to revisit the issue when it becomes public during a permit process. *See e.g., In re Wisconsin Power and Light Columbia Generating Station*, Order Responding to Petitioner's Request that the Administrator Object to Issuance of State Operating Permit (Adm'r, Oct. 8, 2009)

(objecting to Title V renewal where WDNR refused to revisit a prior PSD non-applicability determination that was improperly made).

If DNR had correctly applied the four factors to this the B26 generating bank replacement project, it would have concluded that the project was clearly *not* routine maintenance.

Nature and Extent: The entire generating bank, consisting of 2,090 tubes, was replaced. Ex. G, GP 9/23/10 Ltr. at 4; Ltr. from R. Bremke, GP, to S. Dunn, WDNR (June 3, 2002) (attached to Exhibit G at page 12). This constitutes replacement of an entire component and, therefore, is not routine. Moreover, the replacement could not occur during regular operation of the boiler and, instead, required an outage of approximately two months. Ex. G, GP 9/23/10 Ltr. at 4 (boiler was down 1-/21/02 to 12/13/02); *see also* Ltr. from R. Bremke, GP, to S. Dunn, *supra* (project was expected to take 25 days). This, too, weighs against the project being routine. EPA has previously determined that a 20-day project duration is “significant” and weighs against routine maintenance. See Ltr. From Gregg M. Worley, EPA, to Barry R. Stephens, Tenn. Dept. of Env't. and Conservation at 3.

Moreover, the B26 generating bank replacement project involved redesigning the tube bank and using smaller diameter but thicker walled tubes. See Ltr. from R. Bremke, GP, to S. Dunn, *supra*; Georgia Pacific Section 114 Request-Second Response at 10 (May 23, 2003) (tubes that were 2.5 inches in diameter originally were replaced with tube that were 2.25 inches; tubes that were 2.75 inches in diameter originally were replaced with tubes that were 2.5 inches; tubes that were 0.135 inches thick were replaced with tubes that were 0.150 or 0.165 inches thick) (attached as Exhibit I). Tubes were

specifically ordered for the project and outside contractors were used for the work. *Id.* at 10.

Purpose: The existing generating bank tubes had eroded below standards and the unit was unable to operate long-term without replacing the tubes. Ltr. R. Bremke, GP, to S. Dunn, *supra*. Additionally, the tube bank was redesigned by decreasing tube diameters, increasing open area in the tube bank array, and thereby reduce gas velocity; and by using tubing with thicker walls. Ex. I at 10. These changes were intended to avoid premature erosion that had been causing tube replacements. *Id.*; see also Ex. I, Table 4: Response to Question 8 (“#6 Boiler Outages) (showing numerous generating bank tube leaks causing boiler outages). Projects intended to improve the unit condition, rather than merely fixing leaking tubes on an as-needed basis, especially when the entire component is redesigned for longer life, is not routine.

Frequency: This was the only time that a generating tube bank was replaced on the unit. Ex. G, GP 9/23/10 Ltr. at 4. There were previous projects that replaced a few sections of tubing in the generating bank, but none that involved replacing all of the tubes as this project did. *Id.*

Cost: The project was predicted to cost between \$1,200,000 and \$1,300,000, including \$430,000 for parts and materials and \$868,000 for labor. *See* Ltr. from R. Bremke, GP, to S. Dunn, *supra*. This was more than twice the \$500,000 annual maintenance budget for Boiler B26 at the time. *Id.* These costs are not routine. *See e.g.*, Letter from Gregg M. Worley, EPA, to Barry R. Stephens, *supra* at 4 (“an added cost of nearly one million dollars is high enough to be within the range of costs for projects that have been considered non-routine by EPA in other contexts.”) The costs also appear to

have been capitalized. Ex. G, GP 9/23/10 Ltr. at 4 (noting that the project was identified based on capital appropriation requests).

Conclusion: The nature and extent of the project was significant. It involved a boiler outage to complete, involved replacing an entire component, involved a redesign of the generating bank to improve boiler operation, and the use of different sized component parts. The purpose was to redesign the component to improve long term boiler operations. The project is infrequent—occurring only once. And the cost of over a million dollars is far beyond the cost of routine maintenance on the generating bank tubes. The project was clearly not routine maintenance.

d. The Waterwall Retubing projects were not Routine Maintenance.

The facility replaced significant portions of the boiler furnace area tubes (waterwalls) on Boiler B25 in 2001 and B27 in 1996. DNR concluded that these projects were routine maintenance, but DNR's analysis is largely baseless and a correct analysis, consistent with the law, shows that the projects were clearly not routine.

Nature and Extent: The Boiler B25 project in 2001 involved replacing a portion of each tube across the entire rear wall, entire east wall, and entire west wall. Ex. C, RTC at 5. The Boiler B27 project in 1996 involved replacing a portion of each tube on the entire left wall, on the entire right wall, and on the entire rear wall. Ex. G, GP 9/23/10 Ltr. at 5; Ex. C, RTC at 6. These were very large projects, involving replacement of large amounts of tubing. The tubing was purchased from an outside vendor. Ex. I, Table 3.

The Boiler B25 project occurred over a period of two months, from approximately January 1, 2001 to March 1, 2001. Ex. G, GP 9/23/10 Ltr. at 5. The Boiler B27 project occurred in two stages: from January 6 to 27, 1996, and then from

December 2 to 21, 1996. *Id.* at 6. While DNR’s response to comments indicates that these outages are “relatively short,” there is no basis for that assertion. *See* Ex. C, RTC at 5-6. The fact that an outage was required, rather than being able to conduct the maintenance activity during the regular operation of the boilers, weighs against a finding of routine. Furthermore, EPA has determined that outages of even 20 days are “significant.” *See* Ltr. from Gregg M. Worley, EPA, to Barry R. Stephens, *supra* at 3.

Purpose: DNR’s analysis for the Boiler B25 project again confuses the “purpose” factor by implying that any project that does not increase the maximum rated capacity of a unit is “routine.” Ex. C, RTC at 5. As noted above, this is inconsistent with the Act, the regulation, and prior interpretations by both EPA and DNR. Moreover, the projects did increase the operation of the unit, since they were intended to address metal erosion/wastage that was causing repeated tube leaks. Ex. G, GP 9/23/10 Ltr. at 6; Ex. C, RTC at 6 (noting that the project purpose was to replace tubes that had suffered numerous leaks, had tube thinning, and were unreliable). In fact, the purpose of the B27 project was to increase reliability—which DNR notes is not a “routine” purpose. Ex. C, RTC at 6 (“Tube replacement for the purpose of improving reliability of the boiler is not consistent with RMRR.”).

To summarize: the purpose of both wall retubing projects was to fix long-term problems and improve the overall condition of the boiler; they were not done merely to repair a leak on an as-needed basis without any expectation that the boiler would operate better—with fewer leaks—as a result of the repair. *See* Ex. G, GP 9/23/10 Ltr. at 6 (project justification documents state that holes in wall tubes had been patched numerous

times, but that the boiler was still unreliable and a complete replacement was necessary to make the boiler reliable). This project purpose is not routine.

Frequency: This was the only such project at either boiler. DNR implies that the fact that waterwall replacement projects happened once-per-unit, but at two different boilers, suggests that the project may be “frequent” or “routine”. Ex. C, RTC at 5. This is an erroneous interpretation of the “frequency” factor. The fact that there were two replacements at the plant’s boilers (there are currently 6 boilers, and were 7 boilers at relevant times) indicates that these waterwall replacements are very infrequent events in the lifecycle of any individual unit. As the Seventh Circuit noted in *WEPCO*, a project that occurs once or twice in the life of a unit is not routine. 893 F.2d at 912. Moreover, as noted above, EPA’s longstanding interpretation is that the relevant inquiry is how frequently a project recurs during the life of a unit—not how prevalent the once-per-unit projects might be.

Cost. The Boiler B25 project cost a total of \$234,000 (or \$132,129 in common-year CPI dollars in DNR’s analysis). Ex. C, RTC at 5. While DNR compares this to the total cost for maintenance *for all boilers* at the facility, the relevant comparison is to the cost to maintain B25 on an annual basis—and whether the project cost came from that annual budget or whether it was specifically budgeted.

The B25 project in 2001 was apparently not capitalized. However, this fact is unclear since the facility references its capital appropriation requests for the project. *See* Ex. G, GP 9/23/10 Ltr. at 5. While capitalization weighs heavily against a finding of routine, EPA has never held that failing to capitalize weighs in favor of a finding of routine. Other factors would have to be considered, such as whether the project was

budgeted specifically or whether the costs were applied to the annual maintenance budget for the boiler. DNR did not undertake this analysis.

The cost of the project on B27 cost \$422,456 (or \$269,252 in common year CPI dollars). Ex. C, RTC at 6. The company treated the cost of the project as a capital expenditure. *Id.*; Ex. I, Table 3 (listing “capital” projects). As DNR notes, this weighs against a finding of routine maintenance. Ex. C, RTC at 6.

DNR again makes the mistake of comparing the costs of the B25 and B27 waterwall replacements with the annual cost of maintenance *for all 6 or 7 boilers* at the plant. This inappropriately discounts the high cost of these projects compared to the average or typical annual maintenance cost *for that boiler*. DNR makes no findings comparing the cost of these large component replacement projects to the typical waterwall maintenance costs (i.e., repairing a single tube leak). The capitalization of the B27 project and the cost of the projects compared to each unit’s annual maintenance cost (i.e., each unit’s proportionate share of the total annual maintenance budget for the entire plant) indicate that the projects were not routine.

Conclusion: Overall the projects are clearly not routine maintenance. Entire sections of three different boiler walls were replaced over a period of 2 months on Boiler B25 and a during total of about four weeks on Boiler B27. The purpose of both projects was to improve the condition of the boiler, rather than to merely fix one, or a few, leaking tubes on an as-needed basis without an expectation of improved operation. The projects were a once-ever event in the life of the particular boiler. The cost factor is less clear because it is not clear how the project costs compare to the cost of a typical maintenance project to a boiler wall tube. However in light of the large project scope, it is likely that

the costs are disproportionately high compared to typical, recurring, boiler wall maintenance projects. The capitalization sub-factor is unclear for the B25 project, but weighs against a finding of routine for the B27 project.

As noted above for the cyclone burner replacement project, DNR applies no identifiable standard for reaching its conclusions on routine maintenance. DNR notes that the cost and purpose of the Boiler B27 projects were not consistent with routine maintenance, but nevertheless, finds that “[o]n balance... the evidence is more in favor of the project being RMRR.” Ex. C, RTC at 6. Where two factors weighed against a finding of routine maintenance for the cyclone project, DNR concluded the project was not routine maintenance; whereas DNR concluded that where two factors weighed against such a finding for the waterwall retubing projects¹⁷, the projects were nevertheless routine maintenance. Where even two factors weigh against a finding of routine, DNR’s conclusion that the project is nevertheless routine conflicts with the narrow scope of the exemption and with the heavy burden on the facility to make the requisite showing.

B. The Projects All Resulted In A Significant Net Emissions Increase¹⁸ Based On The Applicable Test (As Would Have Applied To Predict Emission Increases Prior To Each Project).

A “major modification” is “any physical change or change in the method of operation” of a major stationary source that would “result in a significant net emissions increase of any pollutant subject to regulation” under the CAA. *See* 40 C.F.R.

¹⁷ As noted herein, all four factors actually weigh against a finding of routine maintenance when applied correctly.

¹⁸ The following discussion uses the Prevention of Significant Deterioration program regulations. The applicable definitions are identical for the Nonattainment New Source Review program, but found in 40 C.F.R. § 51.165 and Appx. S and Wis. Admin. Code ch. NR 408.

§ 52.21(b)(2)(i) (1980-2002); Wis. Admin. Code § NR 405.02(21) (1996)¹⁹. Whether a project results in a significant “net emissions increase” is determined by calculating the “increase in actual emissions” based on the applicable definitions of “actual emissions” for pre-project and post-project periods. 40 C.F.R. § 52.21(b)(3)(i), (21); Wis. Admin. Code §§ NR 405.02(1), (24)(a). Once the increase is calculated, it is compared to the thresholds in 40 C.F.R. § 52.21(b)(23) or (depending on whether the project was before or after SIP-approval of Wisconsin’s PSD program) Wis. Admin. Code § NR 405.02(27) to determine if the increase is “significant.” A “significant” net emissions increase means an increase in the rate of emissions that would equal or exceed any of the following rates for the following pollutants: 40 tons per year of nitrogen oxides (NO_x); 40 tons per year of sulfur dioxide (SO₂); 7 tons per year of sulfuric acid mist, 25 tons per year of particulate matter (PM), and 15 tons per year of particles of 10 micrometers or less (PM₁₀). 40 C.F.R. § 52.21(b)(23)(i); Wis. Admin. Code § NR 405.02(27)(a).

There are two possible tests used for calculating emissions increases resulting from modifications under the NSR program: (1) the “actual to potential” test and (2) the “actual to projected actual” test.²⁰ The boilers at issue here do not meet the conditions for using the “actual to projected actual” test. The “actual to potential” test was and is the appropriate test for the modifications under consideration in this Petition.

¹⁹ Unless otherwise noted, the references to section of Wis. Admin. Code ch. NR 405 herein are to the 1996 version, which was approved into the Wisconsin SIP in 1999. The 1996 version of the Wisconsin Administrative Code chapter NR 405, which was approved into the Wisconsin SIP in 1999, is attached as Exhibit J.

²⁰ Various names are used for the “actual to projected actual” test, but all refer to the same methodology. *See e.g., New York v. EPA*, 413 F.3d 3, 16, 34 (D.C.Cir. 2005) (referring to the “representative actual” test under the 1992 rule as the “actual to projected actual” test); *see also* 57 Fed. Reg. at 32,323-24 (referring to the “representative actual test” as an “actual to actual,” “future actual projection,” “actual to future-actual”) (July 21, 1992).

1. The “actual to potential” test was the original test utilized by the EPA for measuring emissions resulting from changes at existing sources.

The CAA’s definition of “modification” does not define how to calculate increases in emissions. *New York v. EPA*, 413 F.3d 3, 22 (D.C. Cir. 2005) (“*New York I*”). Instead, the applicable definitions were developed by the EPA. In response to the decision in *Alabama Power Co. v. Costle*, 636 F.2d 323 (D.C. Cir. 1979), the EPA revised its PSD regulations in 1980 and defined an emission increase, for purposes of determining when PSD applies to changes at existing sources, as “any increase in actual emissions from a particular physical change or change in method of operation.” 45 Fed. Reg. at 52,735. Under that definition, determining whether a physical or operational change constitutes a “major modification” requires a comparison of the “actual emissions,” before and after the project. *See e.g.*, 40 C.F.R. § 52.21(b)(3)(i)(a); Wis. Admin. Code § NR 405.02(24)(a)(1).

Under the original PSD regulations promulgated by EPA in 1980, “actual emissions” were defined as:

[T]he actual rate of emissions of a pollutant from an emissions unit, as determined in accordance with paragraphs (ii) – (iv) below.

(ii) In general, actual emissions as of a particular date shall equal the average rate, in tons per year, at which the unit actually emitted the pollutant during a two-year period which preced[es] the particular date and which is representative of normal source operations... calculated using the unit’s actual operating hours, production rates, and types of materials processed, stored, or combusted during the selected time period.

(iii) The Administrator may presume that source-specific allowable emissions for the unit are equivalent to the actual emissions of the unit.

(iv) For any emissions unit which has not begun normal operations on the particular date, actual emissions shall equal the potential to emit of the unit on that date.

45 Fed. Reg. at 52,737 (promulgating 40 C.F.R. § 52.21(b)(21) (1980)); *see also* Wis.

Admin. Code § NR 405.02(1). Thus, under 40 C.F.R. § 52.21(b)(21)(ii) and Wis.

Admin. Code § NR 405.02(1)(a), *pre-project* emissions are determined based on the two years of emissions data preceding the modification.

However, *post-project* emissions do not exist *prior* to the project, when the determination must be made as to whether the project is subject to PSD requirements. Thus, a regulatory presumption or projection of future emissions is necessary. EPA's definition of post-project "actual emissions" contained such a presumption in 40 C.F.R. 52.21(b)(21)(iii) and (iv) (1980). EPA made clear that a pollution source undergoing a non-routine modification will rarely be considered to have "begun normal operations," triggering the potential-to-emit definition of "actual emissions" for post-project emissions in 40 C.F.R. § 52.21(b)(21). EPA explained that, unless exempt as "routine," changes at a facility are presumed to alter the facility sufficiently such that a modified plant cannot be said to have "begun normal operations":

[U]nder the current regulations, changes to a unit at a major stationary source that are non-routine or not subject to one of the other major source [PSD] exemptions are deemed to be of such significance that pre-change emissions for the affected units should not be relied on in projecting post-change emissions. For such units, 'normal operations' are deemed not to have begun following the change, and are treated like new units. Put another way, the regulatory provision for units which have 'not begun normal operations' reflects an initial presumption that a unit that has undergone a non-routine physical or operational change will operate at its full capacity year-round.

63 Fed. Reg. 39,857, 39,858 (July 24, 1998); *see also* 56 Fed. Reg. 27,630, 27,633 (June 14, 1991) (explaining that the use of potential emissions is appropriate as a proxy because the pollution source’s future emissions are “difficult to predict”). Thus, because the pre-change emissions are not reliable in predicting future emissions after a major modification, “the source owner must quantify the amount of the proposed emissions increase. This amount will generally be the potential to emit of the new or modified unit.” 45 Fed. Reg. at 52,677. “The term ‘actual to potential’ is somewhat of a misnomer, because in practice this methodology involves a determination of future actual emissions to the atmosphere.” 63 Fed. Reg. at 39,858.

However, a source owner may rebut the initial presumption that the unit will operate at its full potential "by agreeing to limit its [potential to emit] through enforceable restrictions.” 63 Fed. Reg. at 39,858. That is, implicit in the “potential to emit” test is the presumption that a modification “results in” an increase up to the unit’s full capacity, unless the unit owner accepts enforceable emission limits.²¹ As the EPA explained:

The regulations initially presume that such units will operate year-round at full capacity, but a source owner is free to overcome the presumption by agreeing to limit its potential to emit to any level desired through enforceable restrictions on operations or the use of pollution controls. For example, if limiting the potential to emit results in an insignificant change in emissions...

Detroit Edison, *supra*, Enclosure at 18 n.14.

Thus, under the 1980 regulations, EPA’s method for calculating increases in emissions for modifications at an existing source was as follows. Before a physical

²¹ Even if a plant undergoing a non-routine change could be deemed to have nevertheless “begun normal operations,” the only applicable definition for its post-project “actual emissions” under § 52.21(b)(21) is subsection (iii), which provides that EPA can use the plant’s “allowable emissions” as its post-project “actual emissions.” This is the functional equivalent to the “actual to potential” test.

change or change in method of operation (i.e., modification), “actual emissions” are annual average emissions during a 24-month period, § 52.21(b)(21)(ii) (1980). After a physical change or change in method operation, the “actual emissions” are projected to be the unit’s potential to emit. 40 C.F.R. § 52.21(b)(21)(iv) (1980). “According to EPA... an increase occurs under the 1980 regulations if... a source’s past annual emissions (typically measured by averaging out the two ‘baseline’ years prior to the change) are less than future annual emissions (measured by calculating the source’s potential to emit after the change).” *New York I*, 413 F.3d at 15.

Courts addressing the appropriate test for measuring emission increases – especially those applying the test to sources other than EUSGUs, since the decision *Puerto Rican Cement Co.*, the *WEPCO* decision and the subsequently adopted EPA regulations, have recognized the appropriateness of the “actual to potential” test. See *Sierra Club v. Morgan*, Case No., 07-C-251-S, 2007 U.S. Dist. LEXIS 82760, *51-56 (W.D. Wis. Nov 7, 2007); *U.S. v. Murphy Oil USA, Inc.*, 143 F.Supp.2d 1054, 1102-06 (W.D. Wis. 2001); *U.S. v. Westvaco Corp.*, Civil Action No. MJG-00-2602, 2010 U.S. Dist. LEXIS 113333, *13-14 (D.MD., Sept. 1, 2010).

2. The “actual to projected actual” test for measuring emissions resulting from modifications at existing facilities was codified in 1992 and can only be used if certain conditions are met.

In 1990, the Seventh Circuit issued an opinion rejecting the application of the “actual to potential” test for certain projects in the case before it that it deemed to be “like-kind replacements.” *Wis. Elec. Power Co. v. Reilly*, 893 F.2d 901 (7th Cir. 1990) (“*WEPCO*”). Instead, the *WEPCO* court proposed to apply a projection of future operating hours and emission rates for certain type of projects. In 1991, EPA proposed a

rule change to address and reconcile the Seventh Circuit’s *WEPCO* decision and the First Circuit’s decision in *Puerto Rican Cement, Inc. v. EPA*, 889 F.2d 292 (1st Cir. 1989), which upheld the “actual to potential” test. The resulting rule, known as the “WEPCO Rule,” was intended to clarify when the original “actual to potential” test would apply and when the new “actual to projected actual” test would apply. 56 Fed. Reg. at 27,630-33. Under the rule, EPA allowed the “actual to projected actual” test to measure emissions resulting from changes at all electric utility steam generating units (EUSGUs), regardless of whether the change was “like kind.” 57 Fed. Reg. 32,314, 32,317 (July 21, 1992).

Critically for the modified boilers at issue here, however, the EPA placed two conditions on the use of the “actual to projected actual” test. The first condition is that the test is only available to EUSGUs.²² 63 Fed. Reg. at 39,859; 57 Fed. Reg. at 32,316-17; Detroit Edison, *supra*, Enclosure at 18 (“For units *that are not* ‘electric utility steam generating units... the post-change emissions ‘shall equal the *potential to emit of the unit,*’ ...” (emphasis added)); Memorandum from John Calcagni, Director Air Quality Management Division, USEPA, to David Kee, Director Air and Radiation Division, Region V, USEPA, *Proposed Netting for Modifications at Cyprus Northshore Mining Corporation, Silver Bay, Minnesota*, p. 3 (Aug. 11, 1992)²³; Letter from R. Douglas Neeley, Chief Air and Radiation Technology Branch Air, Pesticides, and Toxics

²² 40 C.F.R. § 52.21(b)(31) defines an EUSGU as a unit capable of supplying more than one third of its potential electric output capacity and more than 25 megawatts of electricity to a distribution system for sale. *See also* Wis. Admin. Code § NR 405.02(11m).

²³ Available at <http://www.epa.gov/region7/air/nsr/nsrmemos/cyprus.pdf>

Management Division, USEPA, to Dr. Donald R. van der Vaart, Division of Air Quality, NC Department of Environment and Natural Resources p. 2 (Aug. 8, 2001)²⁴.

The second condition that the EPA’s “WEPCO rule” requires from those EUGSUs hoping to take advantage of the “actual to projected actual” test is that those utilities must satisfy specific post-project recordkeeping and reporting requirements. This change was intended to address valid concerns raised by the public during the notice and comment rulemaking process:

An environmental group and several State agencies noted that the projected post-change emissions should become an enforceable permit condition in order to commit a source to limit its future emissions to a specific amount and to provide assurance that these projections are reasonable estimates of expected emissions. If a source will not accept such a permit condition, then the source should have to use potential post-change emissions.

57 Fed. Reg. at 32,324. To address these concerns, EPA’s final rulemaking included important monitoring and reporting conditions in the final rule.

After a thorough review of the comments, EPA concludes that the comparison of “actual emissions before” to a projection of “actual emissions after” a physical or operational change at an existing utility steam generating unit is workable and, *with the added safeguard discussed below*, is the most suitable method for evaluating emissions changes at such sources.

...

Several commenters opposing today’s regulatory changes charged that without appropriate assurances utilities could deliberately underestimate future operations (and thus emissions) for the purpose of avoiding review or that even where a forthright estimate is made, the forecast may prove inaccurate. The EPA is concerned that *without appropriate safeguards* increases in future actual emissions that in fact resulted from the physical or operational change could go unnoticed and unreviewed. *For this reason, EPA*

²⁴ Available at <http://www.epa.gov/region7/air/nsr/nsrmemos/ppg2001.pdf>

has added the safeguard explained below.

...

To guard against the possibility that significant increases in actual emissions attributable to the change may occur under this methodology, EPA is clarifying in the final regulations that *any utility which utilizes the "representative actual annual emissions" methodology to determine that it is not subject to NSR must submit* for 5 years after the change sufficient records to determine if the change results in an increase in representative actual annual emissions.

57 Fed. Reg. at 32,324-32,325 (emphasis added); *see also New York I*, 413 F.3d at 34 (describing the 1992 WEPCO Rule as requiring “utilities whose projections included no significant emissions increase” from a modification “to supply permitting authorities with a minimum of five years of data to verify the projections’ accuracy”) (citing 57 Fed. Reg. at 32,336); 63 Fed. Reg. at 39,859.

3. The “actual to potential” test applies to all projects at issue in this Petition.

The projects at issue here occurred at boilers that do not constitute EUSGUs. 40 C.F.R. § 52.21(b)(31) (an EUSGU must be capable of supplying more than 25 MW of electricity for sale to the outside electric grid); Wis. Admin. Code § NR 405.02(11m) (same). Moreover, even if they were EUSGUs, the facility did not conduct the post-project reporting obligations necessary to allow application of the alternative, actual-to-representative-actual test). Notably, Wisconsin DNR has regularly applied the actual-to-potential test to non-EUSGU boilers prior to the recent rule revisions (that are not applicable here). *See* Ex. F, Charter St. Memo at 9; Deposition of Steven Dunn in *Sierra Club v. Dairyland Power Cooperative*, 28:18-29:3 (responding to a question seeking the WDNR’s emission increase methodology, stating “exclusively or almost exclusively for nonutilities what we call the actual to potential test.”) (attached as Exhibit K); *see also id.*

at 31:24-32:6; Ltr. from Michael Ross, WDNR, to Chad Koenigs, Western Lime Co. (May 15, 2001) (“The net emission increase will be deemed significant if the net emissions increase (i.e.: future potential emissions from Kiln #1 minus the past actual emissions from Kiln #1) exceeds the emission rates specified in s. NR 405.02(27)...”) (attached as Exhibit L); Deposition of Steven Dunn in *Sierra Club v. Morgan, et al.*, 92:20-24, 93:16-20, 94:7-9, 96:25-98:10, 109:16-113:12, 155:2-156:8 (attached as Exhibit M); and Ex. F (explaining that under the then-applicable Wisconsin SIP, emission increases from non-exempt physical changes are determined “by subtracting past actual emissions for each pollutant from future potential emissions for each pollutant”); Deposition of Jeffrey Hanson in *Sierra Club v. Morgan, et. al*, 162:1-13, 167:1-16, 196:13-199:5 (same) (attached as Exhibit N). EPA has also regularly required DNR to continue to use that test (for projects occurring prior to adoption of the 2003 NSR Reform regulations into the Wisconsin SIP); Ltr. from Robert Miller to Steven Dunn (re Glatfelter), *supra* at 2 (“as you are aware, a modification that results in a significant emissions increase comparing the unit’s past actual to its future potential emissions, requires the modification to go through PSD review.”); Ltr. from Sam Portanova, USEPA, to Steven Dunn (re Murphy Oil) at 2 (Feb. 24, 2005) (instructing WDNR to apply the actual to potential test).²⁵

²⁵ Available at <http://www.epa.gov/region7/air/nsr/nsrmemos/murphy.pdf>

Project	Pre Project Emissions ²⁶				Potential to Emit ²⁷			Emission Increase		
		NOx	SO2	PM	NOx	SO2	PM	NOx	SO2	PM
B27 Cyclone Replacement 1984	1982	3740.99 ²⁸	11790	53.38 ²⁹	4135.2	12256	808.1	435.54	1310	755.6
	1983	3658.32 ³⁰	10102	51.61 ³¹						
	Average	3699.66	10946	52.495						
B26 Superheater 1981	1979	Not available	Not available	Not Available	674.5	6975.15	459.9	Na	>40 TPY ³²	Na
	1980	Not Available	3196	Not Available						
	Average	Na	Na	Na						
B27 Superheater 1988	1986	3657.49 ³³	10,948.05 ³⁴	1.52 ³⁵	4135.2	12256	808.1	516.97	1330.85	806.7
	1987	3578.96 ³⁶	10902.25 ³⁷	1.28 ³⁸						
	Average	3618.23	10925.15	1.4						
B26 Generating Bank 2002	2000	417.027	3889.72	62.281	674.5	6975.15	459.9	258.416	4351.92	391.77
	2001	415.14	1356.64	74.348						
	Average	416.084	2623.18	68.31						
B25 Waterwall 2001	1999	196.759	539.327	10.542	388.5	3985.8	262.8	218.787	3527.592	253.847
	2000	142.666	377.089	7.363						
	Average	169.713	458.208	8.953						
B27 Waterwall 1996	1994	3305.79	9879.4	184	4135.2	12256	808.1	817.364	2327.59	621.6
	1995	3329.881	9977.42	189						
	Average	3317.836	9928.41	186.5						

²⁶ Source, unless otherwise noted: Georgia Pacific Clean Air Act Section 114 Response, April 10, 2003, Table 2 (attached as Exhibit X).

²⁷ Source, unless otherwise noted: Application for Renewal of Green Bay West Mill (Nov. 20, 2002) (Attached as Exhibit U).

²⁸ Wisconsin DNR, Total Emission Inventory for 1982 (attached as Exhibit O).

²⁹ Id.

³⁰ Wisconsin DNR, Total Emission Inventory for 1983 (attached as Exhibit P)

³¹ Id.

³² Giving the facility the benefit of the doubt, and assuming the emissions during 1979 were equal to the potential to emit, the 2-year average would be 5085.58 tons/year of SO2, and the increase would be 1,889.57 TPY.

³³ Wisconsin DNR, Total Emissions Inventory for 1986 (attached as Exhibit Q)

³⁴ Id.

³⁵ Id.

³⁶ WDNR, Total Emissions Inventory for 1987 (attached as Exhibit R).

³⁷ Id.

³⁸ Id.

II. The Switch To Using Petcoke and Tires as Supplemental Fuels Are Modifications.

In their permit comments, the Petitioners noted that “the company modifies the boilers each time it burns petroleum coke and tires in the boilers” because coke “was not burned until December, 1978” and “tires were not burned until September 3, 1987.” *See* Ex. B, Comments at 2. Petitioners also pointed out in their public comments that, even if these fuels had been originally designed to accommodate these fuels prior to January 6, 1975 (which they were not), that the established interpretation of the alternative fuels exemption in 40 C.F.R. § 52.21(b)(2)(iii)(e)³⁹ and 40 C.F.R. § 60.14(e)(4) is that the exemptions only apply to switches in primary fuels, not to switches that involve adding a supplemental fuel. Ex. B, Comments at 3.

DNR responded that, because it was not the primary authority for the NSR/PSD program or for the NSPS program for most of the history of the plant, it will not make a final determination as to whether the fuel switch constituted a modification. Ex. C, RTC at 7. DNR also implies that EPA is conducting, or has conducted, an investigation on this issue. *Id.* In correspondence with USEPA and a draft Response to Comments shared with USEPA, DNR noted that it had not yet determined applicability of NSPS and PSD related to the switch to pet coke. *See* Ex. E, Email from Susan Kraj, May 12, 2011, at 2 (“On page 7 of your May 5 RTC, under the ‘Addition of Petroleum Coke as a Fuel’ issue, it states, ‘The Department will be discussing this project with the USEPA and moving forward after their input is received.’ ...”).

³⁹ The same language, and therefore interpretation, applies to the nonattainment program in 40 C.F.R. § 51.165 and Appx. S, and in Wis. Admin. Code § NR 408.02(20)(e)2.

DNR cannot avoid making a determination that NSR/PSD and NSPS are applicable requirement that must be included in the permit. At issue is the switch⁴⁰ to pet coke and the switch to tires, and whether either or both constituted a change in method of operation that triggers NSR/PSD and NSPS requirements. 42 U.S.C. §§ 7661a(a), 7661c(a). Each Title V permit must include all applicable requirements; there is no exception for requirements that WDNR does not want to address. Because the permit issued by WDNR does not comply with the requirements of the Clean Air Act, because it fails to include NSR/PSD and NSPS requirements for the modified boilers, the Administrator must object. 42 U.S.C. § 7661d(b)(2); 40 C.F.R. § 70.8(c)(1); *New York Pub. Interest Research Group*, 541 F.3d at 333 n.11; *In re Monroe Elec. Gen. Plant, Entergy Louisiana*, Order Partially Granting and Partially Denying Petition (Adm’r, June 11, 1999) (objecting to Title V permit that failed to ensure compliance with PSD and NSPS, based on modifications made to the plant).

A. Only Changes To A Primary Fuel That Was Originally Contemplated In the Design Of A Boiler And Was Capable of Being Burned Is Exempt From The Definition of “Modification” For Purpose of PSD, Non-attainment NSR, and NSPS.

Pursuant to the regulations in effect in Wisconsin at that time, a “change in method of operation” subject to PSD permitting included a change in method of operation by substituting a fuel that was not previously permitted. *See* 40 C.F.R. § 52.21(b)(2)(i); Wis. Admin. Code § NR 408.02(2)(e)2., 40 C.F.R. § 60.14(e)(4). Notably, fuel changes can be exempt from the definition of a major modification (or modification

⁴⁰ In addition to the first “switch” to pet coke in December, 1978, and to tires in 1983, each time the facility switches its blend to increase the amount of these fuels in the fuel mix it undergoes a modification. This Petition addresses the first switch to avoid duplicating the analysis for each subsequent modification. However, the same analysis applies and each subsequent fuel switch constitutes a new modification.

under NSPS), but only in specific and limited situations. For example, a change ordered under the Energy Supply and Environmental Coordination Act of 1974 or because of a natural gas curtailment under the Federal Power Act), or where a facility: (a) was capable of accommodating the fuel prior to January 6, 1975, and (b) no permit prohibits the use of the fuel. 40 C.F.R. §§ 51.165(a)(1)(v)(C)(2), 52.21(b)(2)(iii)(e)(1), 60.14(e)(4); Wis. Admin. Code § NR 408.02(20)(e). Here, the switch fails to meet these criteria. Consequently, because a non-exempt fuel change has occurred, EPA must object. 40 C.F.R. § 70.6(c)(3); Objection by U.S. EPA to Title V Permit No. 0170004-004-AV, Florida Power Corporation Crystal River Plant at 9 (November 1, 1999) (hereafter “Crystal River Objection”)⁴¹.

B. The Facility Began Burning Petcoke and Tires After January 1975 and There Is No Evidence In The Record That It Was Previously Designed To Accommodate These Fuels.

According to the facility owner, the facility began burning petroleum coke at the boilers in December, 1978, and tires in September, 1987.

Regarding tires, woodwaste and coke:

Q1: Which boilers are burning the above-mentioned fuels?

A1: Tires have been burned in Boilers 4, 5, 6 and 8. They cannot be burned in #7; they may someday be burned in #3.
Woodwaste has been burned in Boiler 6 only.
Coke has been burned in Boilers 3, 4, 5, 6, 7 and 8.

Q2: When (did we begin) burning these fuels (in these) boilers?

A2: Tire burning began on or about September 3, 1987.
Woodwaste burning began on or about July 13, 1988; the burning of woodwaste was terminated on September 19, 1988, and Fort Howard presently has no plans to resume this activity.
Coke burning began in December, 1978.

⁴¹ Available at http://www.epa.gov/region4/air/permits/TitleVObjectionLetters/FL_ObjectionLetters/FPC-CrystalRiver.pdf

Letter from Timothy Mattson, Fort Howard Corp., to Martin Herrick, DNR (December 2, 1988) (attached as Exhibit S). These switches were after January, 1975. Moreover, there is no indication that the boilers were designed with these non-coal fuels in mind. As EPA has previously found, pet coke was not a prevalent fuel and virtually no boilers were designed for it.)⁴²; U.S. EPA Objection to Title V Permit for Reid/Henderson Station, Kentucky at 2 (August 30, 1999) (“Region 4 has determined in similar situations that accommodation for use of a fuel has occurred prior to January 6, 1975, only if such use was included in the final construction specifications of the units in question. We would not expect that the final construction specifications for the units in question here would have addressed petcoke since petcoke was generally not available for use prior to 1975.”)⁴³ (“Reid Henderson Objection”). Notably, merely being able to accommodate a fuel is not enough. The plant must be “designed to accommodate” the fuel. *E.g.*, 40 C.F.R. § 60.14(e)(4); see also Wis. Stat. § 144.391(4)(c)3. (1979) (exempting from the definition of a “modification” only fuels that the facility was designed to burn and only “if that information is included in plans, specification and other information submitted under s. 144.392(2) or under 144.39(1)...); Crystal River Objection, *supra*, Enclosure at 5 (“To interpret this provision as allowing a facility to use ‘any’ fuel that it could possibly burn prior to January 6, 19[75], regardless of whether such fuels were originally contemplated or included in the original design, improperly expands the availability of the intended PSD exemption.”); Reid/Henderson Objection, *supra* at 2; Ltr. from Thomas

⁴² Available at http://www.epa.gov/region4/air/permits/TitleVObjectionLetters/KY_ObjectionLetters/WKEC-DBWilson.pdf;

⁴³ Available at http://www.epa.gov/region4/air/permits/TitleVObjectionLetters/KY_ObjectionLetters/WKEC-ReidHenderson.pdf

Steidl, WDNR, to Mark Reimer, Fort Howard Corp. (Nov. 16, 1989) (interpreting parallel language in Wis. Stat. § 144.391(4)(c)3. to exclude a change to burning tires) (attached as Exhibit T). Like routine maintenance, discussed above, the alternative fuels exemption is an exemption created by regulation that deviates from the language of the statute. It must therefore be narrowly interpreted, and the facility seeking to take advantage of it bears the burden of demonstrating its applicability. The facility here has not demonstrated that the boilers were designed to accommodate pet coke and/or tires.

C. The Use of Pet Coke and Tires Does Not Qualify As A Fuel Switch Within The Meaning of the PSD, NNSR and NSPS Regulations Because They Those Fuels Are Only Supplemental Fuels.

Pet coke and tires were always supplemental to coal fuel—they were never substituted as the primary fuel:

Q3: (What is the) quantity of these fuels burned in pounds per hour for each boiler?

A3: Tire burning has been very erratic due to a very unreliable source of supply until quite recently. However, when supplies are adequate, the blend of tires mixed with other fuels is 10% by weight. Of course, the fuel consumption rate of the boilers and of the Power Plant as a whole is variable due to fluctuating loads. Please note that tires are not necessarily used simultaneously in all operating boilers.

Based on historical average fuel usage by these boilers, and assuming an adequate tire supply, the expected tire consumption rate could be approximately 625 pounds per hour in Boilers 4 and 5, approximately 2,170 pounds per hour in Boiler 6, and approximately 1,420 pounds per hour in Boiler 8. The Power Plant has never burned tires at this cumulative consumption rate. The normal daily consumption of tires is approximately 17-18 tons for the entire Power Plant whenever tires are available for burning. = 2,427/hr
or 58T/day
max.

Woodwaste burning has ceased.

Coke is no longer burned in Boilers 3, 4 and 5 because the very high temperatures required for complete carbon burnout are not reached in these underfeed stoker units. Coke is blended into the fuel of Boilers 6, 7 and 8 at a 12.5% mix by weight. At this mixture, the coke feed rate will average approximately 2,700 lbs. per hour in Boiler 6, 6,650 lbs. per hour in Boiler 7 and 2,010 lbs. per hour in Boiler 8.

Ex. S, Ltr. from Mattson to Herrick.

The pet coke and tire fuel supplementing of the primary fuel (coal) are not exempt from Wis. Admin. Code §§ NR 405.02, 408.02(20) and 40 C.F.R. §§ 51.165, 52.21(b)(2)(i)(e)(1), 60.14(e)(4)-- for boilers other than 9-- because that exemption only apply to primary fuel changes; it does not exempt changes in operation that supplement primary fuels with new or additional alternative fuels. As EPA has explained in numerous Title V objections, 40 C.F.R. § 52.21(b)(2)(iii)(e)(1) does not apply to use of pet coke as a supplemental fuel. *See* Crystal River Objection; Reid/Gardner Objection.

As discussed in *Alabama Power Co. v. Costle*, the PSD exemption at 40 C.F.R. § 52.21(b)(2)(iii)(e)... [was] intended to grandfather “voluntary fuel switches by emission sources which were designed to accommodate the alternative fuels prior to January 6, 1975.” The provision was not intended to provide a loop-hole by which facilities may add various substances, such as waste products or waste fuels, to their primary fuels without being subject to PSD review. The Federal Register notices and background information documents that speak to this particular exemption only reference primary fuels, such as coal, oil and gas. At the time the alternative fuels exemption was promulgated, EPA contemplated “switches” between primary fuels. Therefore, it is a reasonable interpretation of the regulations to limit this exemption to primary fuels and not to apply the exemption to fuel additives that the facility was neither designed nor built to use as a primary fuel. FPC is currently burning coal as their primary fuel. It is EPA’s determination that burning a 95% coal, 5% pet coke blend does not constitute a “switch” to an “alternative” fuel as intended by the exemption. Rather, the blending in of 5% pet coke is a change in the current method of operation that is subject to PSD review. The above interpretations are consistent with... EPA’s longstanding interpretations of the “capable of accommodating” exemption.

Crystal River Objection; *see also* U.S. EPA Objection to D.B. Wilson Station, Kentucky at 2-3 (August 20, 1999) (objecting based on a pet coke switch where the boiler was

constructed after January 6, 1975)⁴⁴; Reid/Henderson Objection at 2 (“We first note that a fuel like petcoke that is used as a supplemental fuel blended with a primary fuel does not qualify as an “alternative” fuel in the sense originally envisioned when the alternative fuel exclusion was added to federal PSD rules.”)⁴⁵.

While DNR appropriately does not extend a permit shield to the boilers for Prevention of Significant Deterioration requirements (or nonattainment new source review or NSPS), DNR cannot avoid addressing this issue by purporting to wait for EPA to resolve it. Because the facility underwent multiple changes in operation by mixing new fuels into its boilers, which are not exempt from the definition of “modification” under the PSD, NNSR, and NSPS programs, EPA must object to the proposed permit. The permit must be revised to include the applicable PSD, NNSR, and NSPS requirements and, if necessary, a compliance schedule to bring the plant into compliance with those requirements.

III. DNR Has Not Determined that The Facility Will Comply With Air Quality Standards and Increments

A. The Wisconsin SIP (Which Defines Applicable Requirements for Title V) Requires Compliance With Increment As A Part of All Permits.

As noted above, each Title V permit must ensure compliance with all applicable SIP requirements. 40 C.F.R. § 70.8(c)(1) (“The [U.S. EPA] Administrator will object to the issuance of any permit determined by the Administrator not to be in compliance with applicable requirements or requirements of this part.”); 40 C.F.R. § 70.2 (defining

⁴⁴ Available at http://www.epa.gov/region4/air/permits/TitleVObjectionLetters/KY_ObjectionLetters/WKEC-DBWilson.pdf;

⁴⁵ Available at http://www.epa.gov/region4/air/permits/TitleVObjectionLetters/KY_ObjectionLetters/WKEC-ReidHenderson.pdf

“applicable requirements” to include requirements of the SIP). Among the requirements of the Wisconsin SIP is the requirement that every permittee, including recipients of renewed operating permits, demonstrate compliance with both the ambient air quality standards and increments. *See* Wis. Stat. § 285.63(1)(b) (formerly at Wis. Stat. § 144.393(1)(b)); 40 C.F.R. § 52.2570(c)(42)(i) (adopting Wis. Stat. § 144.393 (1979) into the Wisconsin SIP); *see also Alabama Power*, 636 F.2d at 363 (SIPs must contain provisions to protect increments, beyond the requirements in the PSD permitting program). Moreover, the requirements of the PSD program are “applicable requirements” for purposes of Title V permitting. 40 C.F.R. § 70.2; *In re Monroe Elec. Gen. Plant* at 2.

B. DNR Has Not Ensured Compliance With Increments By Analyzing All Increment Consuming Emissions at the Plant.

DNR purports to have analyzed the facility’s compliance with increment as part of the permit issuance here. However, in doing so, it failed to adhere to the plain language of the Clean Air Act, Wisconsin Statutes, and the applicable PSD regulations, which state that the “actual emissions” of a major source that is modified after the major source baseline date consume increment. “Actual emissions” for this purpose (and others) is defined specifically in the regulations. DNR takes the position, contrary to the language of the statutes and regulations, that only increases in maximum permitted hourly emission rates consumes increment. Maximum permitted hourly emissions is not one of the definitions of “actual emissions” that apply to define the increment consumption by a modified source. Therefore, DNR failed to ensure compliance with all

applicable requirements (including the Wisconsin SIP and the PSD program) as part of the permit.

1. Background Facts

DNR issued GP a permit in 2004 allowing: (1) an increase in the size of paper machine 9; and (2) an increase in the size of an on-site turbine generator used to generate electricity. *See* Preliminary Determination for 03-DCF-327 (attached as Exhibit V).

DNR has agreed that these changes to the facility debottlenecked the boilers at the facility. *See e.g.*, Memorandum from Don C. Faith III to File, (October 7, 2004) (“The revision request is to include the addition of a replacement steam turbine (for electricity generation) to replace an existing turbine and incorporate this as a part of the recently issued construction permit. Though larger capacity than the existing unit, it will not increase the steam demand beyond what was already accounted for within the review for the paper machine #9 modification process (which also debottlenecks the boilers).”) (attached as Exhibit W).

There is no question that the emission increases from the debottlenecked boilers are emission increases resulting from a major modification to the plant. While EPA has noted in guidance that BACT limits are not required for emission units that do not undergo a change in method of operation or physical change as part of the project⁴⁶, the emission increases from those emission units attributable to the project nevertheless consume increment. However, DNR’s increment analysis for 03-DCF-327, and for the current proposed permit (405032870-P10), did not consider the emissions from the boilers to be increment consuming. *See* Ex. C, RTC at 7; Ex. V, Preliminary

⁴⁶ We respectfully disagree with this interpretation in U.S. EPA guidance, but the issue of BACT applicability is not at issue here.

Determination for 03-DCF-327 at 44-45, Table 2 (“GP Fort James GRB West Paper Mill Increment Consuming Emission Rates”) (not listing stacks S08-S11, which vent emissions from the boilers, as consuming increment). DNR’s basis is confusing and lacks a coherent explanation. DNR’s basis for not including emissions from the modified facility as increment consuming appears to be based on DNR’s unsupported assertion that “increment consumption is determined based on the modeling of allowable emission rate increases that are expressed in pounds per hour rather than tons per year” and DNR’s conclusion that where the permit is not allowing an increase in maximum permitted hourly emission rate, even a source undergoing a major modification does not consume increment. Ex. C, RTC at 7. DNR explicitly refuses to use “actual emissions” from the modified source. *Id.* DNR’s interpretation of the applicable law cannot be squared with the statute and regulations—which require that the “actual emissions” from a modified “major stationary source” consume increment. There is nothing in the regulations or statute that can support DNR’s interpretation, whereby only increases in permitted maximum hourly emission rates consume increment.

First, it should be noted that DNR specifically calculated the emission increase from the plant’s boilers, based on the definitions of “actual emissions”, as part of the PSD permitting for the 2004 project. *See e.g.*, Ex. V, Preliminary Determination for 03-DCF-327 at 51-56. In a table on page 53 of the Preliminary Determination (Ex. V), DNR provided its conclusions showing the amount that emissions would increase from each emission source as a result of the major modification. Those increases included very large increases from the boilers as “Affected Sources”:

	Emission Increases (tons per year)									
	PM	PM ₁₀	NO _x	SO ₂	CO	VOC	Pb	Hg	HF	H ₂ SO ₄
No. 9 Paper Machine (a)										
I. Future Potential Emissions	18.01	18.01	27.34	58.23	22.07	189.55	0.0017	0.00057	---	---
II. Past Actual Emissions	5.45	5.45	9.6	0.058	8.07	26.49	0.000048	0.00005	---	---
III. Emissions Increase	12.56	12.56	17.74	58.17	14	163.06	0.00165	0.00052	---	---
Affected Sources										
IV. Future Potential Emissions	1931.94	1931.58	7368.8	33415.9	2051.7	484.48	1.44	0.23	62.5	483.47
V. Past Actual Emissions	559.71	468.43	4253.82	13627.7	801.48	114.64	0.10952	0.0463	34.62	243.57
VI. Emissions Increase	1372.2	1463.15	3114.98	19788.2	1250.2	369.84	1.33	0.18	27.88	239.9
Sum of No. 9 Paper Machine and Affected Sources (b)										
VII. Future Potential Emissions	1949.95	1949.59	7396.14	33474.1	2073.77	674.03	1.44	0.23	62.5	483.47
VIII. Past Actual Emissions	565.16	473.88	4263.4	13627.8	809.55	141.13	0.1096	0.0463	34.62	243.574
IX. Emissions Increase	1384.8	1475.71	3132.7	19846.3	1264.22	532.9	1.33	0.18	27.88	239.9

Despite calculating emission increases of more than 1300 tons of particulate matter, 3000 tons of NO_x, and 19,000 tons of sulfur dioxide from increased utilization of the boilers due to the modification, DNR failed to account for any of those increases in the increment analysis. This is contrary U.S. EPA's explicit guidance on this issue. *See* Ltr. From Robert B. Miller, USEPA, to Lloyd Eagan, WDNR, (February 8, 2000) (stating that a debottlenecked boiler consumes increment)⁴⁷; Memorandum from Director, Stationary Source Compliance Division, OAQPS, to Michael M. Johnston, Chief, Air Operations Section- Region X, "PSD Applicability Pulp and Paper Mill" (July 28, 1983)

⁴⁷ Available at <http://www.epa.gov/region7/air/nsr/nsrmemos/20000208.pdf>

(emissions from boiler at a modified facility consume increment notwithstanding the fact that the boiler's emission limits did not change).

2. The Clean Air Act And Implementing Regulations Require That The “Actual Emissions”—As Explicitly Defined In The Regulations—From A Modified Major Stationary Source Consume Increment.

DNR's failure to ensure that the plant will not violate increment (and set limits necessary to protect increment) violates the plain language of the Clean Air Act and the implementing regulations. EPA's objection is required.

The Clean Air Act provides that a PSD source cannot “cause, or contribute to, air pollution in excess of any... maximum allowable increase...” 42 U.S.C. § 7475(a)(3). The applicable regulations further specify that the permitted source cannot cause or contribute to a violation of any “maximum allowable increase over the baseline concentration in any area.” Wis. Admin. Code § NR 405.09; *see also* 40 C.F.R. § 52.21(k). The maximum increases over baseline concentration, also known as “increments,” are set forth in Wis. Admin. Code § NR 404.05. To ensure that a facility complies—and does not violate this requirement-- it is necessary to determine what emissions are in the baseline concentration and which are excluded from the baseline concentration, and are therefore increment consuming. Wis. Admin. Code § NR 405.02(4); 40 C.F.R. § 52.21(b)(13)(ii). Emissions excluded from the baseline are the same as emissions that consume increment: exclusion from one category means inclusion in the other.

a) The Regulations Provide That Any “Actual Emissions,” As Defined By Regulation, From A Facility That Has Been Modified Consume Increment.

The applicable regulations specify which emissions are not in the baseline concentration and, therefore, consume increment. According to the applicable regulations:

The following will not be included in the baseline concentration and will affect the applicable maximum allowable increase(s)...

Actual emissions, as defined in paragraph (b)(21) of this section, from any major stationary source on which construction commenced after the major source baseline date...

40 C.F.R. § 52.21(b)(13)(ii), (ii)(a) (emphasis added); Wis. Admin. Code § NR 405.02(4)(b) (same). Note that there is nothing in this definition to support DNR’s interpretation, which would require increases in hourly maximum permitted rates before emissions are excluded from the baseline and considered increment consuming.

The definition of “actual emissions, as defined in paragraph (b)(21)” is defined as “... the average rate, in tons per year, at which the unit actually emitted the pollutant during a consecutive 24-month period which precedes the particular date and which is representative of normal source operation...” 40 C.F.R. § 52.21(b)(21)(ii); see also Wis. Admin. Code § NR 405.02(1)(a). This is the definition that applies. Alternatively, “actual emissions” for a source that has not commenced normal operation can be the potential to emit, Wis. Admin. Code § NR 405.02(1)(c), or DNR can presume the actual emissions to be the “allowable emissions.” 40 C.F.R. § 52.21(b)(2)(iii); Wis. Admin. Code § NR 405.02(1)(b). These are the only definitions of “actual emissions” under § 52.21(b)(21) or Wis. Admin. Code § NR 405.02 that could apply. DNR must apply one

of them to determine the amount of emissions that are excluded from the baseline and “affect the applicable maximum allowable increase” (i.e., increment). 40 C.F.R. § 52.21(b)(13)(ii), (ii)(a); Wis. Admin. Code § NR 405.02(4)(b). DNR’s refusal to address increment consumption from a modified source, absent an increase in permitted hourly emission rates, has no basis in the regulations. An objection is required.

b) The “Actual Emissions” From the Entire Facility Consume Increment.

By its plain language, the “actual emissions” from the entire Georgia Pacific mill consume increment because the entire facility is the “major stationary source”— and the regulations provide that the “actual emissions” from a modified “major stationary source” are to be excluded from the baseline and consume increment.⁴⁸ The regulations do not provide that only the “increase” resulting from the modification consume increment. Nor that the “actual emissions” from the modified units consume increment. Any interpretation that segregates “actual emissions” from individual emission units rather than looking to the emissions from the “major stationary source,” or that calculates emission increases rather than looking to the “actual emissions” as specifically defined in the regulations, as increment consuming, cannot be squared with the language of the regulations.

⁴⁸ EPA’s Environmental Appeals Board recognized this interpretation as reasonable. *See In re Northern Michigan University*, 14 E.A.D. ___, PSD 08-02 Slip Op. at 46 (EAB Feb. 18, 2009) (“one could reasonably construe the statutory, regulatory, and preamble language to mean that *all actual emissions from the modifications to a source* consume increment...”).

c) The EAB's Analysis In *Northern Michigan University* Cannot Be Squared With The Clean Air Act Language Actually Adopted By Congress Or With the PSD Regulations.

The Environmental Appeals Board in *In re Northern Michigan University*, held that the increases in emissions from a major modification consume increment, rather than all of a modified source's "actual emissions" consuming increment. 14 E.A.D. ____, PSD Appeal No. 08-02, Slip. Op. at 41-46 (Feb. 18, 2009). The EAB first identified what it termed a "plausible alternative interpretation"— and then identified references in the congressional record and in agency guidance to support that interpretation. *Id.*

In *NMU*, the EAB recognized that Congress defined "construction" to include "modifications," and therefore major sources modified after the major source baseline date consume increment. Slip. Op. at 45. In determining the amount of increment consumed by a modified source, however, the EAB held that "one could reasonably construe the statutory, regulatory, and preamble language to mean *that all actual emissions from the modifications to a source* consume increment, not that *all actual emissions from the modifications plus actual emissions from the portions of the source that were not modified* consume increment." *Id.* at 46 (italics original). The EAB apparently believed this assertion to be self-supporting since it never explained why this "alternative interpretation" was reasonable, or even "plausible," when the regulatory language is explicit that "actual emissions" from "major stationary sources"-- and not "increases" or emissions from the "modified portions"-- consume increment. The EAB never even undertook a comparison of its "alternative interpretation" to the actual text of the regulation. Respectfully, the EAB's "plausible alternative interpretation" simply cannot be squared with the language of the Act or the implementing regulations. None of

the definitions of “actual emissions” can be stretched to mean “increases,” nor can the definition of “major stationary source” be stretched to mean “from the modification.”

Moreover, while no amount of legislative history or agency history can sanction an interpretation that conflicts with the actual plain language of the statute or regulation, it should also be noted that the EAB’s “alternative interpretation” cannot be supported by the legislative history that the EAB cites, either. That legislative history cited by the EAB consists of testimony by an industry lobbyist on an amendment that was ultimately not adopted by Congress. If anything, the history contradicts the EAB’s interpretation. The history shows that notwithstanding concerns expressed by industry permittees-- that the increment consumption analysis would consider all emissions from a modified plant to consume increment-- Congress *did not* adopt the statutory language that would have limited increment consumption to just emission increases. Rather, Congress adopted the Clean Air Act language that was identified in the legislative history cited by the EAB as making all emissions from modified sources consume increment.

Furthermore, the facts in this case demonstrate why the EAB’s *NMU* interpretation is unreasonable. Because emission increases are measured from a baseline measured in the years just prior to a modification (the 24 months preceding the modification under the 1980 regulations), emission increases can occur from a baseline that is lower than emissions during other historic periods. The result is that if the amount of an emission increase consumes increment, multiple modifications (and therefore increases) can stack increment-consuming emission increase values so that the cumulative increment consuming emissions are greater than the source’s potential to emit. For example, as shown above, Boiler B27 underwent multiple modifications and

multiple emission increases. If each of these increases consumed increment, as the EAB’s *NMU* decision suggests, rather than the “actual emissions” from the “major stationary source,” Boiler B27’s increment consumption for PM would be greater than its potential emissions:

Emission Increase (in TPY)	PM
B27 Cyclone Replacement 1984	755.6
B27 Superheater 1988	806.7
B27 Waterwall 1996	621.6
Total of increases	2183.9
B27’s Potential to Emit⁴⁹	808.1

The fact that the EAB’s *NMU* “alternative interpretation” leads to increment consumption from Boiler B27 that is greater than B27’s potential emissions further demonstrates that it is not a plausible alternative. Additionally, under the *NMU* interpretation, a facility built in 1976 and which later undergoes a major modification to existing equipment, would consume increment for both the original construction and the modification. This further indicates that the *NMU* interpretation is not reasons. Ultimately, the plain language of the statute and regulation must be applied; the “actual emissions” as specifically defined,

⁴⁹ Source, unless otherwise noted: Application for Renewal of Green Bay West Mill (Nov. 20, 2002)

from the “major stationary source” must be treated as consuming increment following a major modification.

d) Even if The EAB’s Interpretation in *Northern Michigan University* Is Followed, DNR Has Nevertheless Still Failed To Properly Account For Increment Consumption.

Even assuming, *arguendo*, that the EAB’s interpretation in *NMU* was correct, and only the increased emissions attributable to a major modification, rather than the “actual emissions” from the “major stationary source”, consume increment, DNR’s analysis would still be erroneous in this case. An objection would still be required.

As noted above, when issuing the permit for the major modification associated with 03-DCF-327, DNR determined that emissions from the boilers would increase and specifically calculated the emission increases. Yet, DNR has not excluded even those increased emissions from the baseline concentration and considered them increment consuming as required by 40 C.F.R. § 52.21(b)(13)(ii) and Wis. Admin. Code § NR 405.02(4)(b).⁵⁰ See *e.g.*, *Northern Michigan University*, Slip Op. at 47 (instructing the agency to calculate increment consuming emissions from a source that underwent a major modification based on the “actual emissions” defined in 40 C.F.R. § 52.21(b)(13)(ii), (21) and part 51 Appx. W § 8.1.2.i & Table 8-2 and 45 Fed. Reg. at 52,717-19, and NSR Manual at C.10-.11, .35-.36, .44-.50). Instead, DNR’s analysis of increment compliance—by requiring an increase in hourly allowable emissions-- effectively presumes that no major modification ever occurred. See Ex. C, RTC at 7-8 (stating that the boilers will not be considered increment consuming because there was no increase in

⁵⁰ Applying this interpretation, each of the increases from the other modifications made to the boilers, as set forth in sections I and II above, also consume increment.

allowable emissions). There is no basis for DNR's interpretation. *See* Memorandum from Directory, Stationary Source Compliance Division, OAQPS, to Michael M. Johnston, Chief, Air Operations Section- Region X, "PSD Applicability Pulp and Paper Mill" (July 28, 1983) (emissions from boiler at a modified facility consume increment notwithstanding the fact that the boiler's emission limits did not change).⁵¹ Moreover, DNR's inclusion in the baseline (and exclusion from increment consumption) of the facility's maximum hourly emission rate, and DNR's consideration of only increases beyond what the facility had the capacity to emit on the major source baseline date, was explicitly rejected by the court in *Alabama Power*. In that case, industry had argued that a facility's ability to emit should be included in the baseline, and increases in emissions that could have been achieved prior to the baseline date, should not count as increment consuming. 636 F.2d at 378-81. The *Alabama Power* court rejected this interpretation, holding that only facilities that began construction but *had not* operated prior to January 6, 1975, could include their maximum capacity to emit in the baseline; sources that had operated prior to January, 1975, had to use their actual emissions as "a more realistic assessment of its impact on ambient air quality." *Id.* at 379. In other words, facilities could not do what DNR allowed in this case: inclusion of maximum capacity to emit in the baseline and modifications without increment consumption as long as the original maximum capacity to emit was not exceeded.

Consequently, DNR's proposed permit failed to ensure compliance with the Wisconsin SIP—which in turn requires that the Georgia Pacific plant complies with increment caps. An objection is required.

⁵¹ To the extent that DNR is interpreting the phrase "actual emissions" in NR 405.02(4)(b) to mean hourly emission rate, there is no basis in the definition of that term for such an interpretation. "Actual emissions" is defined in tons per year, not on an hourly basis.

Conclusion

For the foregoing reasons, the permit fails to meet federal requirements in numerous ways. These deficiencies require that the Administrator object to issuance of the permit pursuant to 40 C.F.R. § 70.8(c)(1). Each of the issues raised in this petition result in a deficient permit. Most of the deficiencies result in unlawful emissions of air pollutants that negatively affect the health and welfare of Petitioners' members.

Dated this 23rd day of July, 2011.

Attorneys for Petitioners

MCGILLIVAY WESTERBERG & BENDER LLC

A handwritten signature in black ink, appearing to read 'D. C. Bender', is written over a horizontal line.

David C. Bender

CERTIFICATE OF SERVICE

STATE OF WISCONSIN)
) ss
COUNTY OF DANE)

I make this statement under oath and based on personal knowledge. On this day I caused to be served upon the following persons a copy of the foregoing Petition to the United States Environmental Protection Agency regarding the Pulliam Power Plant, Permit No. 405032870-P10

To Administrator Jackson via electronic mail to: jackson.lisa@epa.gov
And via Certified Mail, Return Receipt Requested to:

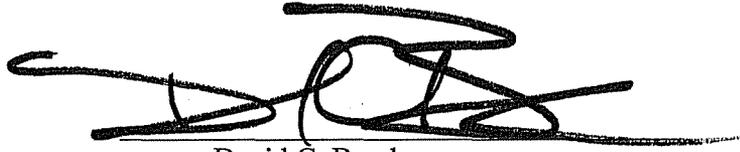
Lisa Jackson
US EPA Administrator
Ariel Rios Building
1200 Pennsylvania Avenue, N.W.
Washington, DC 20460

Cathy Stepp
Wisconsin Dept. of Natural Resources Secretary
101 S Webster St
PO Box 7921
Madison, WI 53707-7921

Georgia Pacific Consumer Products LP
1919 S. Broadway
Green Bay, WI 54307

Georgia Pacific Consumer Products LP
P.O. Box 19130
Green Bay, WI 54307

Dated : July 23, 2011.

A handwritten signature in black ink, appearing to read 'David C. Bender', written over a horizontal line.

David C. Bender

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