> operated in a highly effective manner during all periods of operation, the permit should also require City Utilities to install, operate, maintain, and quality assure inlet SO2 CEMS, in addition to the required stack CEMS, to verify that performance across the SDA is achieved. Since these CEMS are already required by the NSPS Subpart Da, it should not be an imposition to include in the permit. We also concur that any additional need for compliance margin has been accounted for in the analysis for lowering SDA performance from 94 to 92%... and should not be lowered any further.

Ex. U pp. 3-4 (emphasis added). EPA's concerns apply equally in this case. An Administrative Law Judge in Wisconsin held that a static emission limit in the permit for Weston Unit 4 (0.09 lb SO2/MMBtu) did not satisfy BACT. *In the Matter of an Air Pollution Control Construction Permit Issued to Wisconsin Public Service Corporation for the Construction and Operation of a 500 MW Pulverized Coal-Fired Power Plant Known as Weston Unit 4 in Marathon County*, Wisconsin, Case No. IH-04-21 at 9 (Wis. Div. Hrgs. App. Feb. 10, 2006). The ALJ ordered a 90% minimum SO2 removal efficiency be added to the permit to satisfy the requirement of BACT. *Id.* This issue is not being appealed and will be included in the final permit for Weston 4. Similarly, the PSD permit for the Roundup facility in Montana requires 90% control of SO2, as do the permits for Prairie State (98% control) and Indeck – Elwood (92% control) in Illinois. Final PSD Permit for Prairie State Generating Station, No. 189808AAB, p. 16 (April 28, 2005), attached as Exhibit V; Final PSD Permit for Indeck-Elwood LLC, No. 197035AAJ, p. 12 (Oct. 10, 2003), attached as W. The Newmont Mining PSD permit similarly establishes two SO2 BACT limits: 1) 0.09 lb/MMBtu on a 24-hour average when coal sulfur content is greater than or equal to 0.45%; and 2) 0.065 lb/MMBtu on a 24-hour average when the coal sulfur content is less than 0.45% sulfur, combined with a 91% control efficiency. The University of Northern Iowa boiler (Boiler 4) has a BACT limit of 95% reduction. Without a minimum control efficiency included in the permit, the emission controls can under-perform when burning lower sulfur fuels—a result that is inconsistent with the definition of BACT.

H. THE BACT LIMITS SHOULD BE EXPRESSED BY ENERGY OUTPUT.

BACT must be based on the top-ranked pollution control option. Clean production processes must be considered as a pollution control option. 42 U.S.C. § 7479(3); 40 C.F.R. § 52.21(b)(12). As unit efficiency increases, total pollution decreases. *See* U.S. EPA, *Environmental Footprints and Cost of Coal-Based Integrated Gasification Combined Cycle and Pulverized Coal Technologies* (July 2006). Therefore, BACT must consider efficiency of a unit and total pollution emissions, rather than merely focusing on emissions per unit of energy input. In other words, increased efficiency is a method of pollution control because it decreases the total amount of pollution emitted into the environment to produce electric power.

I. The NOx BACT Limit Is Not Based on Maximum Degree Of Reduction From the Top-Ranked Control Option.

The term "best available control technology" means "an emission limitation based on the maximum degree of reduction of each pollutant …." 42 U.S.C. § 7479(3). The Application contains no evidence that the proposed NOx BACT limit of 0.10 lb/MMBtu is based on the maximum degree of reduction that is achievable. Instead, the Application merely asserts that it is "more stringent than the nation-wide range of NOx emissions that represent BACT for the proposed size boiler, as contained in the RBLC." Application at

43. As noted above, a BACT limit cannot be derived by merely looking at prior determinations. Rather, it must be case-specific, based on the top-ranked pollution control option applicable to the permitted source. The Application fails to analyze Selective Catalytic Reduction as a more-effective control option and fails to justify 0.10 lb/MMBtu as the maximum degree of control from the assumed Selective Non-catalytic Reduction.

1. Selective Catalytic Reduction

The Application discusses selective catalytic reduction (SCR), Application at 42, but bases the proposed BACT limit upon selective non-catalytic reduction (SNCR). Modern SCRs routinely achieve NOx removal efficiencies greater than 90%. Ex. X, pp. 1, 15; Ex. Z, p. 30; Ex. Y, p. 77. Detailed analyses of EPA Clean Air Markets data indicates that "90% removal efficiency is currently being achieved by a significant portion of the coal-fired SCR fleet." Ex. X, p. 15. More than 30 units have achieved greater that 90% NOx reduction. Ex. X, p. 1. Ninety percent NOx removal was achieved on 10,000 MW of coal-fired generation in 2004. Ex. Y, p. 77. Many coal-fired units have been guaranteed to achieve greater than 90% NOx reduction. The McIlvaine reports, one of the sources that should be considered in a BACT analysis, indicate three of Haldor Topsoe's SCR installations averaged over 95% NOx reduction during the 2005 ozone season.

An SCR constitutes the top-ranked pollution control option for the proposed boiler. Conservatively assuming a high boiler outlet NOx rate of 0.4 lb/MMBtu, an SCR can achieve a BACT limit of 0.04 lb/MMBtu. This is much lower than the 0.1 lb/MMBtu limit proposed for the Ripley boiler. Other recent BACT determinations, including Western Farmers Electric Coop and Black Hills Corporation, have established BACT limits based upon SCRs. Nevertheless, with no explanation, the NMU purports to base the proposed NOx BACT limit upon an SNCR. This is a defective BACT analysis and does not result in a limit meeting the definition of BACT. Because NMU has not demonstrated that an SCR is not cost effective, the BACT analysis must default to an SCR.

2. Selective Non-Catalytic Reduction

The NMU does not explain how it derived a 0.1 lb/MMBtu NOx limit through the use of an SNRC. Ag. Processing, Inc., has a BACT limit of 0.08 lb/MMBtu based on an SNCR, as does Cargill, Inc. in Nebraska (RBLC ID # NE-0037). If an SNCR is determined to be the top-ranked control for NOx, the BACT limit for the NMU boiler must be assumed to be *at least* as stringent as these prior BACT limits—and even more stringent based on the maximum achievable control efficiency for an SNCR.

III. THE DRAFT PERMIT DOES NOT CONTAIN ANY BACT CONDITIONS FOR MATERIAL HANDLING

The proposed project will result in increased emissions of PM and PM10 from equipment used to handle, convey, and store materials including coal, limestone, and ash. BACT limits apply to these modified sources. However, the draft permit contains no BACT limits for these sources and it appears that neither the applicant nor MDEQ prepared a BACT analysis for these sources.

Other permits include actual numeric BACT limits for material handling, including:

- 0.004 g/dscf for coal and limestone collectors at the Elm Road, WI
- 0.005 g/dscf for coal and limestone collectors at the MidAmerican, IA
- 0.009 g/dscf for coal collectors at the Wygen 2, WY
- 0.005 g/dscf for baghouses at Indeck-Elwood, IL

Limits on emission rates are feasible for the new and modified material handling processes, as evidenced by the fact that other facilities have emission limits. Moreover, emissions from these material handling processes can be measured either through direct tests of emissions or through emission factors applied to the production rate. Therefore, work practice standards cannot be substituted.

IV. THE DRAFT PERMIT UNLAWFULLY EXCLUDES PERIODS OF STARTUP AND SHUTDOWN.

The draft permit purports to excuse periods of startup and shutdown from the BACT limits. Draft Permit p. 7 § 1.7 ("... permittee shall not operate above any of the applicable maximum operating limits... at all times except during periods of starup, shutdown and malfunction.") This is unlawful for at least three reasons. First, a PSD permit must include stringent requirements to ensure compliance with the Clean Air Act during startup, shutdown and malfunction (SSM). Second, the permit contains no emission limits applicable to the boilers during startup, shutdown or "malfunction." Therefore, the emissions are limited *only by the physical limits of the plant* (i.e., maximum theoretical emissions). This represents the worst-case scenario for emissions. These uncontrolled emissions must be used to model air impacts, but the modeling conducted for the proposed Ripley boiler did not assume these emission rates and, therefore, is deficient. Furthermore, the source should be modeled using the design capacity (100 percent load) and the *least stringent* of the applicable limits. This is why many PSD permits—including the draft Desert Rock permit issued by U.S. EPA– contain short term limits in addition to limits with longer averaging times and do not exclude startup, shutdown and malfunction. The draft permit for the Ripley plant, however, has no effective limit on emissions during startup, shutdown and malfunction and, therefore, the maximum allowable emissions are equal to the maximum theoretical emissions. In fact, it appears from the application that the maximum theoretical emission rates were not used to model NAAQS and increment consumption. Rather, the modeling submitted presumed short-term limits that are not proposed to be enforceable in the draft permit. This is unlawful. The permit must either contain short-term emission limits that apply at all times, or the permit must be denied unless and until the applicant demonstrates compliance with NAAQS and increment during worst-case, uncontrolled conditions.

Third, there is no definition of "startup," "shutdown," or "malfunction" in the permit. Therefore, because the permit grants a free pass from all emission limits during these periods the permit is unenforceable. There is no way to determine whether a startup, shutdown and/or malfunction is occurring. To the extent that a startup, shutdown and malfunction exemption is allowed (which it is not), the permit must define these periods and require monitoring and reporting sufficient to determine if such condition is occurring at any given moment.

V. THE STARTUP/SHUTDOWN PLAN MUST BE INCORPORATED INTO THE PERMIT AND SUBJECT TO PUBLIC NOTICE AND COMMENT.

The draft permit requires the NMU to "develop, and submit to AQD for review and approval, a written startup, shutdown and malfunction plan (SSMP)." Draft Permit at p. 7 § 1.5. The permittee is required to comply with the plan, once created. *Id.* This post-permit plan development and approval is unlawful. Moreover, the post-permit plan development and approval violates the public notice and comment provisions of the Clean Air Act. .

VI. THE PERMIT MUST ENSURE THAT THE ASSUMPTIONS MADE FOR MODELING ARE ENFORCEABLE.

In addition to the fact that worst-case conditions during startup, shutdown, and malfunction were not modeled, as noted above, there are a number of additional erroneous assumptions made as a part of the modeling for the Ripley plant boiler.

First, the model only included emissions from the new/proposed stack, exhausting the proposed CFB boiler, and the existing stack exhausting the gas boilers. Application at 67. Specifically, the model failed to include the other emission sources, including material handling (coal and solid fuel unloading), cooling towers, diesel generator, silos, limestone crushing, ash handling, and fugitive road dust. These PM/PM10 emission sources are the most likely to result in violations of NAAQS and increment close to the facility, yet were not even included in the model runs by the NMU. This results in a defective permit that does not comply with 40 C.F.R. § 52.21(k).

Second, the Application states that the following emission rates were assumed in the modeling for the plant:

New Boiler

Pollutant	Maximum Hourly Emission Rate (lb/hour)	Modeled Emission Rate
CO	34.85	4.39
SO2	87.80	11.06
PM10	6.15	0.775
NOx	20.50	2.58

Source: Application at 64

Existing Boilers

Pollutant	Maximum Hourly Emission Rate (lb/hour)	Modeled Emission Rate (grams/second)
CO	24.90	3.14
SO2	86.18	10.86
PM10-Increment Rule	4.44	0.56
PM10-NAAQS Rule	4.79	0.60
NOx	10.24	1.29

Source: Application at 66.

These emission rates do not represent worst case, maximum emission rates for several reasons, in addition to the omission of other emission source such as material handling:

1. The draft permit exempts periods of startup, shutdown and malfunction, during which there are no enforceable limits on emissions and emissions must be calculated based upon maximum theoretical (uncontrolled) emission rates.

2. The hourly emission rates used in the model are based upon the draft permit's emission limits, multiplied by the maximum heat input (205 MMBtu/hour). However, the draft permit does not contain hourly limits. Instead, the draft permit proposes limits based upon 24-hour rolling average and 30-day rolling average for SO2, and an unspecified averaging period for PM, PM10, and NOx. During any 24-hour, 30-day, or unspecified averaging

period, the maximum hourly emission rate can be higher (sometimes much higher) than the average, enforceable, emission rate. Unless the emission limits are enforceable maximum hourly rates, they cannot be relied upon to determine maximum hourly emission rates for modeling.

3. The modeling assumed maximum heat input (maximum load). However, maximum modeled impacts are sometimes, if not usually, at reduced load because the stack exit velocity, temperature, and flow rate are lower at reduced load. Multiple scenarios should be run at various reduced loads, including the corresponding reduced stack temperature, velocity, and flow, to determine the highest impact.

In other words, the model is flawed because it assumed that the permit limits apply at all times, including startup, shutdown and malfunction, assumed that the long-term limits are enforceable maximum hourly limits, and assumed that worst-case impacts occur at maximum heat input. All of these flaws should be corrected, the model should be re-run with correct inputs, and the public should be given an opportunity to review and comment on the results.

Additionally, modeling programs are based on emission inputs in grams per second (or other mass-per-time-period increments). However, the emission limits for most emission sources in the permit are expressed in pounds per input, such as pounds per MMBtu heat input. To convert these input-based emission limits into mass-per-time-period units for modeling, the Application assumed a maximum hourly heat input of 205 MMBtu/hour and, therefore, maximum hourly emission rate. The maximum hourly heat input rate is not included in the permit as an enforceable limit.

The permit limits must either be expressed in terms of total mass emissions per hour (i.e., pounds per hour) , or an enforceable hourly heat input limit in addition to mass per heat input must be included in the permit before the permit limits can be relied on for modeling.

VII. THE MODELING APPEARS TO HAVE OMITTED SOME PM10 EMISSIONS.

The NMU application states that not all emissions were considered in the modeling. Although the discussion is vague, the application implies that some emissions from existing boilers were omitted from the model when determining increment consumption. Application at 65. This suggests that, perhaps, the minor source baseline has not been set and, therefore, emissions from existing boilers at the Ripley plant are considered part of the baseline (rather than consuming increment). This should be verified.

VIII. NMU DID NOT CONDUCT THE REQUIRED PRECONSTRUCTION MONITORING.

It does not appear that any preconstruction ambient air monitoring was done for the project. None was provided in response to Sierra Club's request for all records pertaining to the PSD permit. None was included in the application materials submitted by the NMU. From the Application, it appears that NMU used background concentrations provided by MDEQ via email on August 21, 2006. Application at 69. It does not appear, however, that the background concentrations were from source-specific pre-application monitoring for the Ripley Heating Plant site.

As a prerequisite to obtaining a permit to construct, an applicant must provide the Administrator (MDEQ by delegation) with data about the background ambient air quality in the area that will be impacted by emissions from the new EGU. 40 C.F.R. § 52.21(m). This requires the applicant—the NMU-- to install and operate a series of ambient air quality monitors in the area around the proposed facility for at least twelve months prior to submitting its PSD permit application. To use ambient air monitoring data for a period less than twelve months, the NMU must provide sufficient evidence for MDEQ to determine that a complete and adequate analysis can be accomplished with monitoring data gathered over a period shorter than one year--but not less than 4 months. Such decision must be based on a determination that the shorter period provides sufficient air quality data during a time period, or periods, when maximum concentrations can be expected.

As an applicant, the NMU can only avoid collecting site-specific ambient air quality data is if valid, sufficient, and representative ambient air quality data exists from regional monitoring stations. This only occurs in very limited circumstances. In other words, MDEQ must determine, and the EPA Administrator must agree, that data from regional monitoring stations are representative of ambient air quality at the Ripley Heating Plant site. This requires MDEQ to make specific findings on the record. EPA sets forth three criteria for determining when existing ambient monitoring data is sufficient:

1) monitor location;
2) quality of the data; and
3) "currentness" of the data.

No findings were made to justify using existing air quality data, rather than site-specific data, for the Ripley plant permit.

1) Monitor Location

Pursuant to EPA guidance, to use monitoring data from existing ambient air quality monitors to determine baseline air quality for PSD permitting, the data must be representative of three specific areas:

> (1) the location(s) of maximum concentration increase from the proposed source or modification,
>
> (2) the location(s) of the maximum air pollutant concentration from existing sources, and
>
> (3) the location(s) of the maximum impact area, i.e., where the maximum pollutant concentration would hypothetically occur based on the combined effect of exiting sources and the proposed new source or modification.

EPA concludes that existing air quality data is only representative of these three areas when the proposed source will be located in an area that is generally free from existing point source impacts. When the new or modified source will be located in an area that has multiple air pollution sources <u>and flat terrain</u>, the applicant can only use existing, representative monitoring data that is from (1) a nearby monitoring site, <u>within 10 km</u> of the points of emissions; or (2) from a monitor that is no more than <u>1 km</u> away from either the maximum air pollutant concentration from existing sources or from the area(s) of combined maximum impact from existing and proposed sources.

Moreover, even if the existing air quality monitors were located within 10 km of the Ripley plant site, the monitoring data could still not be used. The proposed location of the new boiler is also a "multisource impact area." There are two existing coal-fired plants (Presque Isle and Marquette Board of Light & Power) as well as several mining companies (Empire Iron and Tilden Mining) contributing to air pollution in the area, as well as a number of other area sources. The existence of these sources disqualifies the Ripley plant from using nearby (≤ 10 km) monitor data.

> If the proposed construction will be in an area of multi-source emissions and in an area of complex terrain, aerodynamic downwash complications, or land/water interface situations, existing data could only be used for PSD purposes if it were collected (1) at the modeled location(s) of the maximum air pollution concentration from existing sources, (2) the location(s) of the maximum concentration increase from the proposed construction, and (3) at the location(s) of the maximum impact area. If the monitor is located at only one of the locations mentioned above and the locations do not coincide, the source would have to monitor the other locations.

Id. (emphasis added). In other words, for a site like the Ripley plant, existing ambient air quality monitoring data can only be used if the existing monitors happen to coincide, exactly, with the areas of highest impact from the new facility, the areas of highest impact from stationary sources in the area, and the areas of highest combined impact from both new and existing sources. There is no demonstration in the record that these requirements have been met. Moreover, it is highly unlikely that they can be met by existing monitoring data. In summary, the NMU was required to conduct air quality monitoring for at least twelve months, prior to submitting its PSD permit application to the MDEQ. This was not done and, therefore, the air quality determination is deficient and the permit cannot be issued.

2) Data Quality

Moreover, even if existing air quality monitors could be used to determine ambient air quality for permitting the modified Ripley plant, the data must meet the same quality standards that on-site monitoring must meet. At a minimum, this includes:

1) continuous instrumentation monitoring
2) documented quality control, including calibration, zero and span checks, and control checks;
3) calibration and span gases should be working standards certified by comparison to Nation Bureau of Standards gaseous Standards Reference Material;
4) minimum 80% data recovery

It is not clear that these data quality requirements were met. Again, even if they were, the monitoring locations must still correspond to the requirements above—including location at the points of maximum impact and maximum ambient air concentration.

3) Data "Currentness"

Additionally, if existing ambient air monitoring data could be used to permit the new sources at Ripley, the data must be current. This means that the data must have been collected in the most recent three years (2004-2007). It does not appear that this requirement was met.

Moreover, using data other than site-specific air monitor data violates the Clean Air Act. The plain language of the Clean Air Act requires site-specific air quality monitoring for every PSD permit application. 42 U.S.C. §§ 7475(e)(1) ("The review provided for in [42 U.S.C. § 7475(a)] shall be preceded by an analysis in accordance with regulations of the Administrator... of the ambient air quality at the proposed site and in areas which may be affected by emissions from such facility for each pollutant..." (emphasis added)), 7475(e)(2) (providing that ambient air monitoring "shall include continuous air quality monitoring data gathered for purposes of determining whether emissions from such facility will exceed the maximum allowable increases or the maximum allowable concentration permitted under this part.") Specifically, the plain language of the Clean

Air Act requires that ambient air quality data be collected at and around the site of the new source, and be collected specifically for the purpose of determining whether the source will cause a violation of NAAQS or increment. The Act does not contemplate using ambient air monitoring from a distant location as a surrogate.

IX. THE PSD INCREMENT INVENTORY WAS DEFICIENT.

PSD permit applicants are responsible for conducting modeling to demonstrate that they:

1) do not exceed the increment unless adequate offsets are produced;
2) do not contribute to violations in other states (under CAA § 126);
3) do not adversely impact a Class I area; and
4) do not produce an unacceptable growth associated air pollution impact.

40 C.F.R. § 52.21(k). After the applicant determines the impact area, it must develop emission inventories which are used to perform dispersion modeling for NAAQS and increment analysis. This must include all stationary sources within the region, as well as recently permitted sources that have not yet been constructed. The applicant must also create an increment inventory, which must include data from:

- Increment-consuming sources within the impact area;
- Increment-consuming sources outside the impact area that affect increment consumption in the impact area.
- Building dimensions, stack heights, and other factors necessary to determine downwash from increment consuming facilities.

The applicant must determine whether any major sources have increased emissions since the major source baseline date and whether any source, including minor, area, and traffic sources, has increased emissions since the minor source baseline date.

The Application states that only the new CFB boiler proposed for the Ripley plant and the existing boilers at the Ripley plant increment consuming. Application at 71. The We Energies Presque Isle plant was not modeled as increment consuming. However, because the Presque Isle plant was modified after the major source baseline date, it is not included in the baseline and is "increment consuming." 40 C.F.R. § 52.21(b)(13)(ii). The modeling must be revised to account for the Presque Isle Power Plant's ("PIPP") status as a modified, increment consuming source.

1. The State of Michigan Determined PIPP To Have Been Modified.

On July 10, 2003, the State of Michigan, through the Attorney General representing the MDEQ, filed a motion to intervene in the lawsuit filed by the United States against Wisconsin Electric Power Company ("WEPCO") for violations of the Prevention of Significant Deterioration program of the Clean Air Act. *See* Mot. of State of Michigan Seeking Intervention, *United States v. Wisc. Elec. Power Co.*, Case No. 2:03-cv-00371-CNC, Docket # 18 (E.D. Wis., July 10, 2003). A Complaint by the MDEQ and Michigan Attorney General were allowed on July 21, 2003. *See* Compl. in Intervention of Michael A. Cox, Attorney General of the State of Michigan, ex rel. Michigan Department of Environmental Quality, *United States v. Wisc. Elec. Power Co.*, Case No. 2:03-cv-00371-CNC, Docket # 22 (E.D. Wis., July 21, 2003), attached as Exhibit AA. The MDEQ determined, presumably prior to filing a complaint against WEPCO, that the PIPP underwent one or more major modifications. According to the representations made by MDEQ to the Court:

> In 1999, Wisconsin Electric constructed a modification at an electric generating unit at the Presque Isle Generating

> Station that resulted in a net emission increase over 40 tons per year or more of SO2 and/or NOx. Wisconsin Electric constructed the modification without obtaining a PSD permit and without applying best available control technology as required by Section 165(a) of the Clean Air Act, 42 U.S.C. § 7475(a).

Id. ¶ 28.

2. The United States Determined That The PIPP Underwent Major Modifications.

On April 29, 2003, the United States, at the request of the US EPA, filed a civil action against WEPCO for PSD modifications at numerous plants, including PIPP. Compl., *U.S. v. Wisc. Elec. Power Co.*, Case No. 03-cv-00371 (E.D. Wis., April 29, 2003). Before filing this complaint, the US EPA was required to find that WEPCO violated the Clean Air Act. 42 U.S.C. § 7413(a)(1) ("Whenever, on the basis of information available to the Administrator, the Administrator finds that any person has violated or is in violation of any requirement... the Administrator may... bring a civil action..."). Therefore, the filing of the Complaint against WEPCO for PSD violations at PIPP was, necessarily, based on a finding of violation based on information available to US EPA.

Among the information available to the EPA was a memo from George Czerniak, Chief of Air Enforcement and Compliance, EPA Region 5, to Sandra Lee, Office of Regional Counsel, regarding "Potential Major Modifications at Wisconsin Electric Power Company Facilities," dated February 23, 2001, attached as Exhibit BB. In the memo, Mr. Czerniak states that EPA review of documents submitted by WEPCO "shows 16 potential major modifications at five WEPCO power plants." *Id.* One of those projects was the 1999 replacement of reheat tubes on PIPP unit 7. *Id.* at EPA5GEN018775. The project cost