LANDERS & PARSONS, P.A.
ATTORNEYS AT LAW

CINDY L. BARTIN
DAVID S. DEE
JOSEPH W. LANDERS, JR.
JOHN T. LAVIA, III
FRED A. McCORMACK
PHILIP S. PARSONS
ROBERT SCHEFFEL WRIGHT

HOWELL L. FERGUSON
OF COUNSEL

VICTORIA J. TSCHINKEL
SENIOR CONSULTANT
(NOT A MEMBER OF THE FLORIDA BAR)

310 WEST COLLEGE AVENUE
POST OFFICE BOX 271
TALLAHASSEE, FLORIDA 32302
TELEPHONE (904) 681-0311
TELECOPY (904) 224-5595

RECEIVED
MAR 6 1997
BUREAU OF
AIR REGULATION

March 6, 1997

Douglas Beason
Assistant General Counsel
2600 Blair Stone Road
Twin Towers Office Building
Tallahassee, Florida 32399

Re: Piney Point Phosphates, Inc.

Dear Mr. Beason:

On behalf of Manatee County, we have enclosed the following materials for your review:

1. A letter dated March 4, 1997 from RTP Environmental Associates Inc., plus attachments; and

2. A document entitled "Comments on Piney Point Phosphate's Proposed Repair List" by Mr. R.C. Berry, plus attachments.

These documents may help the Department of Environmental Protection with its evaluation of Piney Point's plan to rebuild and restart an existing sulfuric acid plant in Manatee County.

The attached letter from RTP Environmental Associates Inc. (RTP) discusses the applicable EPA regulations and the key factors that must be considered when DEP determines whether Piney Point's project involves "routine" repairs. RTP has discussed these issues with Mr. David Solomon, the Chief of the EPA section at Research Triangle Park that is responsible for evaluating New Source Review issues. Based on RTP's analysis and its discussions with Mr. Solomon, RTP has concluded that the proposed work at Piney Point's facility is not routine, and is likely to require preconstruction permits pursuant to the NSPS and PSD regulations.

Mr. R.C. Berry is a resident of Manatee County who offered the enclosed materials for the County's consideration. According to Mr. Berry, he worked as a Senior Project Manager with Monsanto Enviro-Chem Systems and he is knowledgeable about the original design of the sulfuric acid plant. Mr. Berry is concerned that Piney Point's proposed construction may result in significant changes to the sulfuric acid plant.

Manatee County would be happy to meet with the Department at any time or place to discuss these issues in more detail. Please call me if you have any questions.

Sincerely,

David S. Dee

cc: Richard Garrity
Bill Thomas
Howard Rhodes
Clair Fancy
Al Linero
John Reynolds
Brian Beals
Ellen Porter
Joyce Chandler
David Solomon
Hamilton Rice
Karen Collins
Paul Amundsen
Pat Comer
Linda Reel

/vc:MAN37

RTP ENVIRONMENTAL ASSOCIATES INC.®

AIR • WATER • SOLID WASTE CONSULTANTS

239 U.S. Highway 22 East
Green Brook, New Jersey 08812-1909

(908) 968-9600
Fax: (908) 968-9603

March 4, 1997

David S. Dee, Esq.
Landers & Parsons
310 W. College Avenue
Tallahassee, FL 32302

Dear Mr. Dee:

RTP Environmental Associates, Inc. ("RTP") is assisting Landers & Parsons and the Board of County Commissioners of Manatee County ("County") with its evaluation of various environmental issues concerning a proposal (December 17, 1996 letter from Ivan Nance to W. C. Thomas) by Piney Point Phosphates, Inc. ("Piney Point") to refurbish and restart a fertilizer manufacturing facility in Manatee County that closed several years ago. The County's initial issues concerning NSPS and PSD applicability were contained in a January 16, 1997 letter from you to Douglas Beason of the Florida Department of Environmental Protection ("Department"). Piney Point's counsel submitted a response in a February 7, 1997 letter from Paul H. Amundsen to Doug Beason. Subsequent to these letters, the Department requested additional information from Piney Point in a February 20, 1997 letter from W. Douglas Beason to Richard W. Moore (attached as Exhibit A). The Department also conducted a meeting with Piney Point representatives and yourself on February 24, 1997 at the Piney Point plant.

In your January 15, 1997 letter to Douglas Beason, you cited the federal regulatory language which required NSPS and PSD review for physical changes or changes in method of operation at an existing facility which result in an increase in emissions. As stated, the determination of NSPS and PSD applicability is a two-fold test. In addition, your letter discussed in detail the NSPS and PSD issues involved in calculating emissions increases for reactivating shutdown or inoperable sources. This letter mainly discusses the issues involved in determining whether the proposed modifications are routine or are a "physical change" subject to regulation under the NSPS and PSD rules.

At this time, the primary disagreements between the County and Piney Point relate to whether the proposed modifications are "routine" as defined by NSPS and PSD regulations and whether the proposed modifications would result in an increase in emissions as defined by the NSPS and PSD regulations. There are other issues of concern to us, but this letter focuses on these two main issues relating to the restart. We have included at the end of this letter a request for additional information necessary for us to further evaluate the regulatory applicability of the proposed project.

Routine Maintenance

Piney Point has maintained that the proposed maintenance and repair activities are routine in nature and suggested that either Manatee County does not understand the phosphate fertilizer industry or misconstrued the facts. For example:

> *"Manatee County's letter discloses a serious misunderstanding of scheduled maintenance turnarounds in the phosphate fertilizer industry. These turnarounds can, and frequently do, involve substantial work including replacement of plant components at great expense. Such was the case in February 1989--a scheduled maintenance turnaround that Manatee County refers to at least twice in its letter. However, the stated downtime of 415 hours on page 4 of Manatee County's letter is not unusual for such plant turnarounds. It is true that plant operations were suspended at that time for routine maintenance, including repair and replacement of components, and the work was substantial. But as DEP is well aware, this is not extraordinary in the industry, but is commonplace."*[1]

Or:

> *"Furthermore, with the exception of the cooling tower that was damaged by the 1993 'No Name Storm' these plant components are commonly repaired or replaced in the course of scheduled plant turnarounds, including the work on the mist eliminators. In summary, Manatee County's premise statement that Piney Point Phosphates, Inc.'s submittals and communications do not adequately address the issues is simply wrong. It is true that the county is seriously misinformed, but DEP certainly has a full and adequate understanding of Piney Point Phosphates, Inc.'s program towards the restart of the plant."*[2]

Also at the meeting, Piney Point repeatedly maintained that the proposed modifications are routine and commonplace in the industry. However, they did not provide specific examples to verify these assertions about the specific pieces of equipment to be modified or replaced at the Piney Point plant. Without such information, such statements by Piney Point[3] and their representatives cannot be verified. Further, as discussed in the next section on emissions increases, the planned Piney Point activities at an operating plant may not result in increases in actual emissions, thus not satisfying the second criteria for a modification requiring review under NSPS and PSD regulations. However, in the case of Piney Point, emissions increases must be evaluated in the context of a shutdown facility.

---

[1]February 7, 1997 letter from Paul H. Amundsen to Doug Beason, p. 5.
[2]Ibid, p. 8.
[3]For example, *"The specific work undertaken by Piney Point Phosphates, Inc. is squarely within 'routine maintenance, repair, and replacement of component parts.'"* Ibid, p. 11.

In its regulatory analysis, Piney Point cited a Florida case[4] where, in August 1995, an operating permit was renewed for a sulfuric acid plant inactive for six years and, in November 1995 in a separate action, the plant was allowed to replace the catalyst with a different design which increased the plant's production. In that case, the Department agreed with that applicant that no physical modifications were necessary to achieve the higher production rate so the work did not constitute a "physical change." At this time, we cannot argue the specifics of that case but it does not appear on the surface that the catalyst replacement in that case is of the same magnitude as the activities proposed for the Piney Point plant. Further, we do not know whether that project was closely reviewed by EPA for consistency with EPA national policy on NSPS and PSD requirements.

Piney Point states that: *"Such determinations [like the above Department's review of a phosphate fertilizer plant restart] are more useful than precedents involving other kinds of industries in other states, like iron ore operations in Minnesota or power plants in Wisconsin."*[5] However, Piney Point cites the case of Wisconsin Electric Power Company v. Reilly 893 F.2d 901 (7th Cir. 1990, attached as Exhibit B), herein referred to as "WEPCO," as follows:

> *"The work proposed by Piney Point Phosphates, Inc. is the opposite of that considered by the court in WEBCO (sic). Except for the cooling tower that was damaged by a windstorm, the components that are being repaired or replaced by Piney Point Phosphates, Inc. are items that are routinely repaired or replaced during scheduled turnarounds at fertilizer plants. Therefore, no physical change is involved. Consequently, the project can be neither an NSPS modification nor an NSR major modification."*[6]

However, Piney Point's analysis of WEPCO is based on the prior assumption that the proposed modifications are routine and fails to consider one of the most important issues addressed in WEPCO--what criteria should be used to determine whether modifications are routine or whether they meet the criteria requiring NSPS and PSD review. WEPCO was a landmark decision which clarified the applicability of NSPS and PSD regulations to modifications and calculating emissions increases. One of the most basic WEPCO issues was determining what type of modifications could be considered routine and thereby excluded from NSPS and PSD review. In WEPCO, the court supported EPA's decision that the WEPCO modifications were not routine based on:

---

[4]Ibid, pp. 8-9.
[5]Ibid, p. 8.
[6]Ibid, p. 12.

> *"...a case-by-case determination by weighing the nature, extent, purpose, frequency, and cost of the work, as well as other relevant factors, to arrive at a common-sense finding."*[7] (emphasis ours)

It is our opinion that applying these same criteria to the Piney Point plant shows that the proposed modifications are, in fact, not routine. Our discussion on these points is given below.

In WEPCO, EPA observed that the nature and extent of the project was substantial: WEPCO proposed to replace sixty-foot steam drums and air heaters during successive nine-month outages at each unit. The court found that:

> *"Certainly, the magnitude of the project (as well as the down-time required to implement it) suggests that it is more than routine."*[8]

In the case of Piney Point, a substantial portion of the existing plant will be replaced, including some substantive pieces of the equipment such as the acid towers. Piney Point states that:

> *"But for the cooling tower and the completion of routine maintenance, repair, and replacement of component parts, which is in progress and will continue over the next ten months, the Piney Point plant would be operational right now."*[9] (first emphasis ours, second emphasis in original)

It is our opinion that repair activities which take as long as ten months to complete are not routine, particularly when Piney Point has retained:

> *"...regular employees of Piney Point Phosphates, Inc. who work at that plant every day to keep components in operational condition."*[10]

Thus, the nature and extent of the modifications do not appear to be routine. Past work activities at the plant during the last five years presumably would have included most routine repair and maintenance functions. Although Piney Point asserts that the proposed activities are routine because they are performed during scheduled turnarounds, Piney Point also admits that scheduled turnarounds typically take about two weeks, in contrast with ten months for the proposed repairs.

---

[7]September 9, 1988 memorandum from Don R. Clay to David A. Kee (attached as Exhibit C), p. 3.
[8]Wisconsin Electric Power Company v. Reilly, 30 Environment Reporter-Cases (ERC) 1896.
[9]February 7, 1997 letter from Paul H. Amundsen to Doug Beason, p. 6.
[10]Ibid, p. 6.

In WEPCO, the court also found that the purpose, frequency and cost of the work also supported EPA's decision that the modifications were not routine. The purpose of the WEPCO modifications was to rehabilitate the capacity of aging units and extend the useful life of the units. EPA concluded that such modifications were not routine. The court supported this position, stating:

> *"While it is certainly true that the repair of deteriorated equipment will contribute to the useful life of any facility, it does not necessarily follow that the repairs in question would extend the 'life expectancy' of the facility."*[11]

Piney Point's plant was built in 1965 and modified about 1975. The December 17, 1996 letter from Ivan Nance to W. C. Thomas contains an extensive list of proposed repairs and replacements to the Piney Point plant. The modifications would appear not only to rehabilitate the plant but also to completely modernize many integral components of the plant. Based on the current age of the plant and the extensive modifications proposed, it would be expected that this project would significantly extend the useful life of the Piney Point plant. Although Piney Point maintains that the existing plant will be shut down after construction of a new sulfuric acid plant, Piney Point has given the Department no timetable for shutting down the existing plant. The extensive modifications proposed could be expected to increase the life expectancy of the existing plant thus allowing Piney Point to continue to use the existing plant for the foreseeable future.

Similarly, the court rejected WEPCO's assertions that simple equipment replacement did not constitute a physical change for purposes of the Clean Air Act's modification provisions. The court noted that:

> *"Further, to adopt WEPCO's definition of 'physical change' would open vistas of indefinite immunity from the provisions of NSPS and PSD. Were we to hold that replacement of major...systems...does not constitute a physical change (and is therefore not a modification), the application of NSPS and PSD to important facilities might be postponed into the indefinite future. There is no reason to believe that such a result was intended by Congress."*[12]

In WEPCO, previous cases of some modifications could be documented but no cases of identical like-kind replacements for some components such as the steam drums and air heaters could be found. Thus, because of the infrequency of some replacements, the overall WEPCO modifications were not considered to be routine. The court supported EPA's decision here, noting that: *"While it is true that some repair and replacement programs are routine, it does*

---

[11]Wisconsin Electric Power Company v. Reilly, 30 ERC 1897.
[12]Ibid, 30 ERC 1894.

not necessarily follow that all such programs are routine."[13] At this time, Piney Point has not provided specific information as to the normal frequency of the proposed repairs and replacements for each piece of equipment, either for actual facilities or previously for the Piney Point plant. We cannot make a determination on this point in the absence of such information.

Finally, WEPCO asserted that the cost, magnitude and nature of its project are irrelevant for purposes of the routine exception to NSPS and PSD because the WEPCO modifications were not a reconstruction (i.e., did not exceed 50% of the capital cost of a comparable new facility). The court rejected this argument[14], noting the distinct differences between reconstruction and modification, and that the modification provisions applies to <u>any</u> physical change, without regard to cost, that causes an increase in emissions. Thus, while Piney Point submitted a P.E. statement in its December 17, 1996 letter to Mr. W. C. Thomas that the project was not reconstruction as defined by the Clean Air Act, this has no bearing on whether the project is a modification for NSPS and PSD purposes or whether the proposed repair and replacement activities are routine.

Further, the court agreed with EPA findings in WEPCO that the purpose, frequency, and cost of the WEPCO program did suggest that it was not routine. In the case of WEPCO:

> *"...in terms of annualized costs, the renovation project will cost $7.8 million, as compared to $51.6 million for a new 400 megawatt plant. Thus, [WEPCO] renovation costs represent approximately 15 percent of replacements costs."*[15]

According to Piney Point, the minimum expenditure needed to return the plant to operating condition was estimated to be $13 million, about 30% of Piney Point's estimate for a "comparable new plant" (i.e., $42 million). Thus, the relative expenditure planned for Piney Point is greater than for WEPCO and should not be considered as routine. Again, additional information from Piney Point, such as the expected range of annual capital expenses for normal maintenance and repairs activities at either an actual similar facility or previously at Piney Point (for example, during the past five years), would be useful to evaluate whether such expenditures are routine.

---

[13]Ibid, 30 ERC 1896.

[14]Piney Point uses the same argument in its WEPCO discussion: *"Manatee County puts forward the premise that the sheer magnitude of the work alone establishes that it is not 'routine.' ... It is legally incorrect because a project's cost, alone, is determined by the 'reconstruction' regulations, discussed <u>supra</u>, which are inapplicable here."* February 7, 1997 letter from Paul H. Amundsen to Doug Beason, p. 12.

[15]September 9, 1988 memorandum from Don R. Clay to David A. Kee, p. 6.

Based on EPA regulations and WEPCO (among other decisions), it is our opinion that the Piney Point modifications are not routine based on the nature, extent, purpose, and cost of the activities. At this time, we have no information to evaluate the frequency of the proposed activities. Nonetheless, we do not believe that extensive replacement and rehabilitation of a currently inoperable facility should be construed as routine maintenance. WEPCO, rather than being the opposite of Piney Point's situation as asserted by Piney Point, is directly comparable to Piney Point's planned modifications. For these reasons, the project qualifies as a physical change under the modification definitions of NSPS and PSD.

Emissions Increase

As noted earlier, the Piney Point modifications present an unusual set of circumstances relating to the modification and reactivation of a shutdown source. In your January 15, 1997 letter to Douglas Beason, you provided a complete discussion on calculating emissions increases for shutdown sources and extensively cited EPA guidance dealing with modifications to shutdown sources, which we will not repeat here. However, we do wish to make the following points with respect to emissions increases as they relate to this case.

Piney Point maintained at the meeting that the scope of the proposed modifications could have been performed piecemeal during the past five years and not triggered NSPS or PSD review. This might be true if the facility had been operational at normal capacity during this period since they may not have increased actual emissions at the plant. However, the facility has not operated since the middle of 1992 and is currently not operational. This is a critical distinction.

Piney Point also maintains that the modifications will not increase plant emissions. However, this statement is based on allowable (i.e., permitted) or potential (i.e., if the facility were operational) emissions while NSPS and PSD regulations for modifications are based on actual emissions, which represent the actual operating conditions and, for PSD, the history of the facility. For NSPS, emissions increases are based on short-term emissions immediately before and immediately after the modifications. Currently, maximum short-term emission rates are zero since the facility is not operational. This is analogous to WEPCO's Unit 5, for which EPA stated: *"Regarding Unit 5, you state that 'safety concerns' dictated the decision to shut down that unit. Based on this information, we are unable to rely on WEPCO's statements as to maximum 'achievable' capacity in determining the emissions changes at each of these units. Thus, for example, in the case of unit 5, the current [NSPS] capacity must be regarded as zero."*[16]

[16]October 14, 1988 letter from Lee M. Thomas to John W. Boston (attached as Exhibit D), p. 5.

For PSD, emissions increases are calculated by comparing annual emissions after the modification to actual annual emissions during a representative two-year period during the 5-year contemporaneous period (which, for this project, began during 1992). Since the plant operated for only 3410 hours in 1992 and not at all during 1993 through 1996, any future significant plant operations would therefore increase actual plant emissions. In WEPCO, EPA used a representative two year period during the 5-year contemporaneous period under actual operating conditions to establish prior actual WEPCO emissions to calculate emissions increases. Again, further discussions of emissions increases, particularly for PSD purposes at shutdown facilities, are contained in your January 15, 1997 letter to Douglas Beason.

In summary, for the reasons given above and in your January 15, 1997 letter to Douglas Beason, we believe that the Piney Point modifications are not routine and qualify as "physical changes" and would also result in increases in actual emissions. Thus, the proposed modifications fulfill both portions of the two-fold test for modifications and should be subject to NSPS and PSD permitting requirements.

Additional Information Request

At this time we would urge the Department to contact David Solomon, Acting Chief of EPA's Integrated Implementation Group in Research Triangle Park at 919-541-5375, either directly or through Region IV, to review the available information and obtain a preliminary determination whether the Piney Point activities are subject to NSPS and PSD requirements. Mr. Solomon has been included for copies on the relevant letters from the County and Piney Point in this case and, based on discussions with Gary D. McCutchen of our staff, has read the correspondence provided. We feel that it is important for the Department to consult with EPA to confirm that any decision in this case is consistent with EPA national policy given the significant NSPS and PSD policies involved and the interplay with WEPCO issues.

The information requested in the Department's February 20, 1997 letter from W. Douglas Beason to Richard W. Moore (Exhibit A) should provide a basis for finalizing the applicable requirements of NSPS and PSD to the Piney Point modifications. Additional information which may be necessary include the following:

- Documentation on the relative frequency of the proposed repairs and replacements at similar plants and, more importantly, at the Piney Point plant for each piece of equipment (citations of projects of the magnitude and extent of the proposed Piney Point activities would be useful, particularly where written correspondence exists that EPA or state agencies reviewed the regulations and determined that NSPS and PSD did not apply and for what reasons);

- Specific information on the range of expected annual costs of routine repair and maintenance at similar plants and, more importantly, at the Piney Point plant (particularly lands owned by the Federal Goverment and Indian Reservations located in such State. No disapproval with respect to a State's failure to prevent significant deterioration of air quality shall invalidate or otherwise affect the obligations of States, emission sources, or other persons with respect to all portions of plans approved or promulgated under this part.

(b) *Definitions.* For the purposes of this section:

(1)(i) *Major stationary source* means:

(*a*) Any of the following stationary sources of air pollutants which emits, or has the potential to emit, 100 tons per year or more of any pollutant subject to regulation under the Act: Fossil fuel-fired steam electric plants of more than 250 million British thermal units per hour heat input, coal cleaning plants (with thermal dryers), kraft pulp mills, portland cement plants, primary zinc smelters, iron and steel mill plants, primary aluminum ore reduction plants, primary copper smelters, municipal incinerators capable of charging more than 250 tons of refuse per day, hydrofluoric, sulfuric, and nitric acid plants, petroleum refineries, lime plants, phosphate rock processing plants, coke oven batteries, sulfur recovery plants, carbon black plants (furnace process), primary lead smelters, fuel conversion plants, sintering plants, secondary metal production plants, chemical process plants, fossil fuel boilers (or combinations thereof) totaling more than 250 million British thermal units per hour heat input, petroleum storage and transfer units with a total storage capacity exceeding 300,000 barrels, taconite ore processing plants, glass fiber processing plants, and charcoal production plants;

(*b*) Notwithstanding the stationary source size specified in paragraph (b)(1)(i) of this section, any stationary source which emits, or has the potential to emit, 250 tons per year or more of any air pollutant subject to regulation under the Act; or

(*c*) Any physical change that would occur at a stationary source not otherwise qualifying under paragraph (b)(1) of this section, as a major stationary source, if the changes would constitute a major stationary source by itself.

(ii) A major stationary source that is major for volatile organic compounds shall be considered major for ozone.

(iii) The fugitive emissions of a stationary source shall not be included in determining for any of the purposes of this section whether it is a major stationary source, unless the source belongs to one of the following categories of stationary sources:

(*a*) Coal cleaning plants (with thermal dryers);

(*b*) Kraft pulp mills;

(*c*) Portland cement plants;

(*d*) Primary zinc smelters;

(*e*) Iron and steel mills;

(*f*) Primary aluminum ore reduction plants;

(*g*) Primary copper smelters;

(*h*) Municipal incinerators capable of charging more than 250 tons of refuse per day;

(*i*) Hydrofluoric, sulfuric, or nitric acid plants;

(*j*) Petroleum refineries;

(*k*) Lime plants;

(*l*) Phosphate rock processing plants;

(*m*) Coke oven batteries;

(*n*) Sulfur recovery plants;

(*o*) Carbon black plants (furnace process);

(*p*) Primary lead smelters;

(*q*) Fuel conversion plants;

(*r*) Sintering plants;

(*s*) Secondary metal production plants;

(*t*) Chemical process plants;

(*u*) Fossil-fuel boilers (or combination thereof) totaling more than 250 million British thermal units per hour heat input;

(*v*) Petroleum storage and transfer units with a total storage capacity exceeding 300,000 barrels;

(*w*) Taconite ore processing plants;

(*x*) Glass fiber processing plants;

(*y*) Charcoal production plants;

(*z*) Fossil fuel-fired steam electric plants of more that 250 million British thermal units per hour heat input, and

(*aa*) Any other stationary source category which, as of August 7, 1980, is being regulated under section 111 or 112 of the Act.

(2)(i) *Major modification* means any physical change in 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 Act.

(ii) Any net emissions increase that is significant for volatile organic compounds shall be considered significant for ozone.

(iii) A physical change or change in the method of operation shall not include:

(*a*) Routine maintenance, repair and replacement;

(*b*) Use of an alternative fuel or raw material by reason of an order under sections 2 (a) and (b) of the Energy Supply and Environmental Coordination Act of 1974 (or any superseding legislation) or by reason of a natural gas curtailment plant pursuant to the Federal Power Act;

(*c*) Use of an alternative fuel by reason of an order or rule under section 125 of the Act;

(*d*) Use of an alternative fuel at a steam generating unit to the extent that the fuel is generated from municipal solid waste;

(*e*) Use of an alternative fuel or raw material by a stationary source which:

(*1*) The source was capable of accommodating before January 6, 1975, unless such change would be prohibited under any federally enforceable permit condition which was established after January 6, 1975 pursuant to 40 CFR 52.21 or under regulations approved pursuant to 40 CFR subpart I or 40 CFR 51.166; or

(*2*) The source is approved to use under any permit issued under 40 CFR 52.21 or under regulations approved pursuant to 40 CFR 51.166;

(*f*) An increase in the hours of operation or in the production rate, unless such change would be prohibited under any federally enforceable permit condition which was established after January 6, 1975, pursuant to 40 CFR 52.21 or under regulations approved pursuant to 40 CFR subpart I or 40 CFR 51.166.

(*g*) Any change in ownership at a stationary source.

(*h*) The addition, replacement or use of a pollution control project at an existing electric utility steam generating unit, unless the Administrator determines that such addition, replacement, or use renders the unit less environmentally beneficial, or except:

(*1*) When the Administrator has reason to believe that the pollution control project would result in a significant net increase in representative actual annual emissions of any criteria pollutant over levels used for that source in the most recent air quality impact analysis in the area conducted for the purpose of title I, if any, and

(*2*) The Administrator determines that the increase will cause or contribute to a violation of any national ambient air quality standard or PSD increment, or visibility limitation.

(*i*) The installation, operation, cessation, or removal of a temporary clean coal technology demonstration project, provided that the project complies with:

(*1*) The State implementation plan for the State in which the project is located, and

(*2*) Other requirements necessary to attain and maintain the national ambient air quality standards during the project and after it is terminated.

(*j*) The installation or operation of a permanent clean coal technology demonstration project that constitutes repowering, provided that the project does not result in an increase in the potential to emit of any regulated pollutant emitted by the unit. This exemption shall apply on a pollutant-by-pollutant basis.

(*k*) The reactivation of a very clean coal-fired electric utility steam generating unit.

(3)(i) *Net emissions increase* means the amount by which the sum of the following exceeds zero:

(*a*) Any increase in actual emissions from a particular physical change or change in method of operation at a stationary source; and

(*b*) Any other increases and decreases in actual emissions at the source that are contemporaneous with the particular change and are otherwise creditable.

(ii) An increase or decrease in actual emissions is contemporaneous with the increase from the particular change only if it occurs between:

(*a*) The date five years before construction on the particular change commences; and Say 4-15-

(*b*) The date that the increase from the particular change occurs. Say 4-15-98

(iii) An increase or decrease in actual emissions is creditable only if the Ad-

∴ The decrease (i.e. shutdown) is contemporan
with the increase (startup) if construction
begins by 4-15-97. Presumption under the
law is that it would have begun within reasonable time
following request, if allowable under the rules.

the extent and cost of maintenance activities at the Piney Point plant during the past five years);

- Specific information as to whether the proposed changes will involve a change in the method of operation at the facility (Piney Point's December 17, 1996 letter notes that some equipment will be replaced to different configurations), particularly useful would be process flow diagrams for the existing plant and the plant after the proposed modifications;

- Determining the current operating potential of the existing facility in its present condition with respect to both short-term (i.e., hourly) and long-term (i.e., annual) emissions and production rates;

- Determining the extent of physical changes to other air pollution sources at the facility, such as the fertilizer plant, for the same consideration of potential regulatory issues involving modifications as given to the sulfuric acid plant here;

- Determining actual emissions for all phases of the existing Piney Point facility during the contemporaneous period (i.e., during the past 5 years);

- Determining whether the replacement of the sulfur storage tank and auxiliary boiler should be considered part of the sulfuric acid plant for purposes of the modification regulations (also, what effect on emissions will be caused by replacing the existing 96 MMBTU/hour auxiliary boiler with a 190 MMBTU/hour auxiliary boiler and, if fired, what NSPS requirements are triggered by this larger boiler); and

- Determining the effect of the proposed physical changes on the expected life expectancy of the plant.

Summary

plural noun - singular verb

Our conclusions on the applicability of NSPS and PSD has been based on a review of the available information in the context of the Department's and EPA's regulations. Due to the unusual circumstances of this case (modification and reactivation of an shutdown source), we have relied on landmark decisions by the courts and EPA guidance documents to correctly interpret the regulations. In your January 16, 1997 letter to Douglas Beason, you cited the NSPS and PSD review requirements for modifications and referenced EPA guidance documents which addressed how emissions increases for shutdown sources should be calculated. In this letter, we have addressed how to determine whether modifications are routine based on the WEPCO decision.

All of the information listed in the introduction was reviewed by Gary D. McCutchen of our staff (formerly Chief of EPA's New Source Review Section in Research Triangle Park) and David Solomon (current Chief of EPA's section involving New Source Review issues in Research Triangle Park). Based on this available information, both these individuals believe that NSPS and PSD preconstruction permits should likely be required for the proposed Piney Point modifications. Although Piney Point has already begun construction of the modifications, it is important to note that these permits must be obtained prior to initiation of construction because, as noted by the WEPCO court *"As Judge Boggs, dissenting in 'National-Southwire', reasoned: 'The purpose of the 'modification' rule is to ensure that pollution control measures are undertaken when they can be most effective, at the time of new or modified construction.'"*[17]

If you have any questions, please feel free to contact us at 908-968-9600.

Sincerely,

RTP ENVIRONMENTAL ASSOCIATES, INC.®

Donald F. Elias
Principal

DFE/WEC/wec

Attachments

cc: W. Corbin, G. McCutchen, LPPPP Project File/RTP Env. Associates, Inc.
H. Hamilton Rice, Jr., Esq./Manatee County Attorney's Office

[17] Wisconsin Electric Power Company v. Reilly, 30 ERC 1894.

EXHIBIT A

February 20, 1997 letter to Richard W. Moore
from W. Douglas Beason

Department of Environmental Protection

Lawton Chiles
Governor

Marjory Stoneman Douglas Building
3900 Commonwealth Boulevard
Tallahassee, Florida 32399-3000

Virginia B. Wetherell
Secretary

VIA-FACSIMILE (904) 425-2447

February 20, 1997

Richard W. Moore, Esq.
Amundsen & Moore
502 East Park Avenue
Tallahassee, Florida 32301

Re: Piney Point Phosphate, Inc.

Dear Mr. Moore:

In confirmation of our conversation yesterday morning, representatives of Piney Point Phosphate, Inc. and the Department will meet at the Department's Southwest District Office on February 24, 1997, in an effort to address the issues raised by Manatee County in its correspondence dated January 16, 1997. The Department would suggest the meeting at the District Office commence at 1:00 p.m.. and will be followed by an on-site visit to the Piney Point facility.

As I noted during our conversation, one item of particular concern with regard to Piney Point's correspondence dated February 7, 1997, is the assertion that "Piney Point has, to date, committed or expended upwards of $2 million towards restarting the Piney Point Plant with additional, substantial expenditures ongoing or immediately forthcoming." Prior to the receipt of this correspondence, the Department was not aware of the fact that Piney Point had already initiated activities associated with refurbishing and restarting the plant. The undertaking of activities associated with restarting the plant may be problematic given the distinct possibility the initiation of these type of activities may be subject to preconstruction review under the Department's New Source Performance Standards and the Prevention of Significant Deterioration Program. Chapters 62-210 and 62-212, F.A.C. Obviously, your client will want to take this possibility into consideration with respect to any future activities related to restarting the facility.

A second item of concern involves Piney Point's pending application for a PSD permit for a new sulfuric acid plant to *replace* the existing plant. It is my understanding that Piney Point intends to continue to pursue the issuance of this PSD permit (The underpinnings of the PSD analysis presuppose the new plant will *replace* the existing plant). Apparently, Piney Point intends to refurbish and operate the existing plant only until such time the new plant comes on-line. The assertion that Piney Point intends to both refurbish the existing plant and obtain a PSD permit for the construction of a new plant is perplexing. Why would Piney Point spend approximately $16 to $18 million over the course of the next 10 months to refurbish the existing plant when the refurbished plant will only operate until the new plant comes on-line? With respect to the PSD Permit, the Department's Notice of Intent to Issue is predicated on the permanent shut-down of the existing facility.

In preparation for the scheduled meeting, the Department has developed questions concerning the items listed in Exhibit I of Piney Point's letter to W. C. Thomas, dated December 17, 1996:

(a) For all items listed as proposed repairs and relocation, please provide the date the item was originally placed in use at the sulfuric acid plant ; the item's projected useful life on that date; the item's present capacity to process sulfur; the cost of repairs to be undertaken on the item; the projected useful life of the item after repairs; the burner's capacity to process sulfur after repairs; any change to the hourly rate of emissions and total plant annual emissions that may result from repair to the burner; the estimated cost of installing the item if it were new rather than repaired and the useful life of the item if it were new. Also, please provide a history of previous repair and/or replacement of component parts since September 1, 1975.

(b) For those items listed as being refurbished/rehabilitated, please provide the above requested information *and* describe exactly what will be undertaken to accomplish refurbishing/rehabilitating; and what effect the refurbishing/rehabilitating will have on overall sulfuric acid processing or processing capacity at the plant.

(c) For those items listed as being replaced, please provide the information requested in paragraph (a) above *and* describe exactly what is being installed to replace the existing item and detail any differences between the existing item and the replacement part; also explain the effect the replacement will have on overall sulfuric acid processing or processing capacity at the plant.

(d) For those items listed as new, such as the mist eliminators, the pumps described in item #18, miscellaneous piping/valves, and the new motor control center, please explain what performs the function of each item now, and provide the information requested in paragraph (a) for the existing and the new components and detail what effect the addition of these items will have on the overall sulfuric acid processing or processing capacity at the plant.

(e) With respect to the "Certification of Cost of Proposed Repairs and Equipment Replacement to the Existing Sulfuric Acid Plant at Piney Point[1]," the Department needs to review information concerning the various assumptions underlying the financial analysis performed by Mr. Harman in concluding the estimated cost of repairs would be approximately $16.9 million. Similarly, the Department needs to review the same type of information with respect to the underlying assumptions and financial analysis performed by Mr. Hart in concluding the estimated cost "will not exceed 50% of the cost of building a new grass roots plant of the same capacity..."

Thank you for your continued cooperation and the Department looks forward to a constructive meeting this coming Monday.

Sincerely,

W. Douglas Beason

W. Douglas Beason
Assistant General Counsel

WDB/hc
cc: Dr. Richard Garrity
Al Linero
David S. Dee

[1] Exhibit II to Piney Point's letter dated December 7, 1996.

EXHIBIT B

Wisconsin Electric Power Co. v. Reilly
893 F.2d 901 (7th Cir. 1990)

WISCONSIN ELECTRIC POWER CO. v. EPA

U.S. Court of Appeals
Seventh Circuit

WISCONSIN ELECTRIC POWER COMPANY, *Petitioner*, v. WILLIAM K. REILLY, Administrator and UNITED STATES ENVIRONMENTAL PROTECTION AGENCY, *Respondents*, Nos. 88-3264 and 89-1339, January 19, 1990

Clean Air Act

EPA/state authority to regulate (▸110.09)

Stationary source standards — In general (▸110.1001)

[1] Company replacing air heaters and steam drums in coal-fired power plant has made physical change to plant that may be modification subject to review under Clean Air Act, because: (1) Congress intended sources to undergo Air Act review when they make any physical change that causes increase in emissions; (2) replacement of air heaters and steam drums may be like-kind replacement of equipment, but is also physical change in plant; and (3) narrow definition of physical change would allow existing emission sources to delay or avoid meeting full Air Act requirements when making major equipment changes.

EPA/state authority to regulate (▸110.09)

Stationary source standards — In general (▸110.1001)

[2] Replacement of air heaters and steam drums in coal-fired power plant is physical change that is not routine maintenance or repair, and may subject modification to Environmental Protection Agency review under Clean Air Act, because: (1) EPA determined that project was substantial based on equipment being replaced, costs, and shutdown time of units at plant; (2) EPA and company were unable to identify projects of like magnitude that avoided Air Act review; (3) changes go beyond merely maintaining facility, and are designed to extend life expectancy of plant; and (4) cost factors covered in EPA's regulations on facility reconstruction do not apply to facility modifications.

EPA/state authority to regulate (▸110.09)

Stationary source standards — In general (▸110.1001)

[3] Company's modifications of coal-fired power plant, combined with increase in emissions, triggered application of new source performance standards under Clean Air Act, and Environmental Protection Agency properly calculated emissions increase by comparing baseline of actual emissions in 1987 against maximum capacity of plant after renovation. EPA was not required to use baseline year selected by company as representative of plant's performance, because agency's regulations are directed at obtaining testing representative performance without regard to timing of tests.

EPA/state authority to regulate (▸110.09)

Stationary source standards — In general (▸110.1001)

Prevention of significant deterioration — Emission source requirements (▸110.3515)

[4] Environmental Protection Agency used improper approach in determining that modification of coal-fired power plant would submit project to Clean Air Act review in area where standards for prevention of significant deterioration applied, because: (1) agency assumed in its calculations that facility changes were modification of sort that would trigger PSD review, and (2) agency assumed that facility would have potential to emit continuously for 24-hour periods, when facility had not done so in past.

EPA/state authority to regulate (▸110.09)

Stationary source standards — In general (▸110.1001)

[5] Environmental Protection Agency properly rejected company's request to switch to low-sulfur coal as measure to control emissions when EPA reviewed application of new source performance standards under Clean Air Act, because Congress has expressed preference in Air Act for use of control technologies over fuel-switching.

On petitions for review of final action by Environmental Protection Agency concerning application of Clean Air Act standards to changes in coal-fired power plant; affirmed in part and vacated in part, and remanded to EPA.

Henry V. Nickel, Wash., D.C., for petitioner.

Gregory B. Foote, EPA, Wash., D.C., for EPA.

Before Richard D. Cudahy and Joel M. Flaum, circuit judges, and Robert A. Grant, district judge.*

Full Text of Opinion

Cudahy, Circuit Judge. The Petitioner, Wisconsin Electric Power Company ("WEPCO"), challenges two final determinations issued by the Environmental Protection Agency (the "EPA"). In these determinations, the EPA concluded that WEPCO's proposed renovations to its Port Washington power plant would subject the plant to certain pollution control provisions of the Clean Air Act, as amended, 42 U.S.C. §§7401 *et seq.* (1982). We affirm in part, vacate in part and remand to the EPA.

I. The Underlying Dispute

A. Relevant Provisions of the Clean Air Act

Some discussion of the Clean Air Act is required before turning to the merits of this case. In 1970, Congress enacted the Clean Air Act Amendments, Pub. L. No. 91-604, 84 Stat. 1676, to establish minimum air quality standards that would regulate the emission of certain pollutants into the atmosphere. To this end, Congress instructed the EPA to develop National Ambient Air Quality Standards ("NAAQS") that would specify the maximum permissible concentration of air pollutants in different areas across the country.

In section 111 of the 1970 Amendments, Congress required the EPA to promulgate New Source Performance Standards ("NSPS") in order to regulate the emission of air pollutants from new sources. These standards addressed hourly rates to emission and, in addition to new sources, applied to modifications of existing facilities that created new or increased pollution. Indeed, section 111(a)(2) of the Act stated that NSPS would apply to

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

42 U.S.C. §7411(a)(2) (emphasis supplied). Congress then defined "modification" as

> *any physical change* in, or change in the method of operation of, a stationary source *which increases the amount of any air pollutant emitted* by such source or which results in the emission of any air pollutant not previously emitted.

42 U.S.C. §7411(a)(4) (emphasis supplied).

Subsequently, faced with only varying degrees of success in controlling pollution in different parts of the country, Congress enacted the Clean Air Act Amendments of 1977, Pub. L. No. 95-95, 91 Stat. 685 (codified at 42 U.S.C. §§7401-7642 (1982)). Congress revised the NSPS so that regulated sources of pollution would have to use "the best system of continuous emission reduction which (taking into consideration the costs of achieving such emission reduction, and any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated. . . ." 42 U.S.C. §7411(a)(1)(C). In addition, Congress added a program for the Prevention of Significant Deterioration ("PSD"), concerned with increases in total annual emissions, to ensure that operators of regulated sources in relatively unpolluted areas would not allow a decline of air quality to the minimum level permitted by NAAQS. Air quality is preserved in this program by requiring sources to limit their emissions to a "baseline rate"; regulated owners or operators in areas that have attained NAAQS must obtain a permit before constructing or modifying facilities. 42 U.S.C. §7475(a)(1). Congress also essentially adopted its NSPS definition of "modification" for the PSD program. 42 U.S.C. §7479(2)(C).

From this statutory framework, EPA promulgated regulations for both the NSPS and PSD programs. In this case, its regulations concerning modifications are central. The EPA defines "modification" in substantially the same terms used by Congress.

> [A]ny physical or operational change to an existing facility which results in an increase in the emission rate to the atmosphere of any pollutant to which a standard applies shall be considered a modification within the meaning of section 111 [42 U.S.C. §7411] of the Act.

40 C.F.R. §60.14(a) (1988). To determine whether a physical change constitutes a modification for purposes of NSPS, the EPA must determine whether the change increases the facility's *hourly rate* of emission. 40 C.F.R. §60.14 (1988). For PSD purposes, current EPA regulations provide that an increase in the *total amount* of emissions activates the modification provisions of the regulations. 40 C.F.R. §52.21(b)(3) (1988)

Even at first blush, the potential reach of these modification provisions is apparent: the most trivial activities — the replacement of leaky pipes, for example — may trigger the modification provisions if the change results in an increase in the emissions of a facility. As a result, the EPA promulgated specific exceptions to the modification provisions:

> The following shall not, by themselves, be considered modifications under this part:
>
> (1) Maintenance, repair, and replacement which the Administrator determines to be routine for a source category . . .
>
> (2) An increase in production rate of an existing facility, if that increase can be accomplished without a capital expenditure on that facility.
>
> (3) An increase in the hours of operation. . . .

40 C.F.R. §60.14(e) (1988) (NSPS program); *see* 40 C.F.R. §52.21(b)(2)(iii) (1988) (PSD program). These regulations (and the statutes from which they derive) are the focal point of this case.

B. WEPCO's Proposed Life-Extension Project

WEPCO's Port Washington electric power plant is located on Lake Michigan north of Milwaukee, Wisconsin. The plant consists of five coal-fired steam generating units that were placed in operation between 1935 and 1950. Each generating unit has a design capacity of 80 megawatts, but the recent performance of some of the units has declined due to age-related deterioration of the physical plant.

WEPCO and its consultant, Bechtel Eastern Power Corporation, conducted a Plant Availability Study in 1983 to examine and assess the condition of the power plant. As a result of the Study, WEPCO concluded "that *extensive renovation* of the five units and the plant common facilities is needed if operation of the plant is to be continued." Letter from Thomas J. Cassidy, Executive Vice President, of WEPCO, to Jacqueline K. Reynolds, Secretary to the Public Service Commission of Wisconsin, at 2 (July 8, 1987) [Cassidy Letter] (emphasis supplied). The Study noted that the air heaters on the first four units had deteriorated severely, while the rear steam drums in units 2 through 5 had experienced serious cracking.[1] Air heater deterioration prevented units 1 and 4 from operating at full capacity, while the potential for steam drum blowout required a reduction in pressure (and output) in units 2 and 3. The possibility of catastrophic failure (steam drum blowout) in unit 5 was so great that WEPCO shut down the unit completely.

As a result of this Study, WEPCO submitted a proposed replacement program (which it termed a "life extension" project) to the Wisconsin Public Service Commission for its approval, as required by state law. Wis. Stat. §196.49 (1987). WEPCO explained in its proposal that "[r]enovation is necessary to allow the Port Washington units to operate beyond their currently planned retirement dates of 1992 (units 1 and 2) and 1999 (units 3, 4 and 5) . . . [and that renovation would render the plant] capable of generating at its designed capability until year 2010. . . . Cassidy Letter at 1-2. Among the renovations required were repair and replacement of the turbine-generators, boilers, mechanical and electrical auxiliaries and the common plant support facilities. *Id.* at 1. After preliminary review of the program, the Public Service Commission consulted the Wisconsin Department of Natural Resources (which then consulted EPA Region V) to determine whether WEPCO needed to obtain a PSD permit before commencing the repair and replacement program. David

* The Honorable Robert A. Grant, Senior District Judge for the Northern District of Indiana, is sitting by designation.

[1] Air heaters preheat combustion air to improve the efficiency of the steam generating units. *Steam: Its Generation and Use* 13-4 (1978) (Babcock & Wilcox). Steam drums separate saturated steam from water within the boiler. *Id.* at 1-5.

Kee, the Director of EPA Region V's Air and Radiation Division, then referred the matter to EPA Headquarters. *See, e.g.*, 40 C.F.R. §60.5 (1988) (discussing the EPA's procedures regarding determinations of construction or modification).

EPA staff members conferred with WEPCO representatives between March and September 1988 to gain additional information regarding the proposed repair and replacement project. On September 9, 1988, EPA Acting Assistant Administrator Don R. Clay issued a memorandum in which he preliminarily concluded that the project would subject the plant to both NSPS and PSD requirements. Memorandum from Don R. Clay, Acting Assistant Administrator for Air and Radiation of the EPA, to David A. Kee, Director of Air and Radiation Division, Region V (Sept. 9, 1988) [Clay Memorandum]. The Clay Memorandum pointed out that the project would constitute a "physical change" resulting in an increase of production and emissions, which would therefore subject the plant to the relevant strictures of the Clean Air Act. *Id.* at 3-4. Further, the Clay Memorandum dismissed WEPCO's contention that the program was routine and was therefore exempt from the requirements of NSPS and PSD. This conclusion was adopted *in toto* by EPA Administrator Lee M. Thomas. Letter from Lee M. Thomas, Administrator of the EPA, to John Boston, Vice President of WEPCO (Oct. 14, 1988) [Thomas Letter].

Following the Thomas Letter, WEPCO continued to conduct capacity tests on the units. Based upon these tests, Assistant Administrator Clay issued a "revised final determination" that generally affirmed the EPA's earlier findings, but modified the baseline figures used by the EPA for units 2 and 3. Letter from Don R. Clay, Acting Assistant Administrator for Air and Radiation of the EPA, to John W. Boston, Vice President of WEPCO (Feb. 15, 1989) [Supplemental Determination].

Alleging that the EPA has misconstrued both the Clean Air Act and its own regulations, WEPCO appeals the EPA's final determination. We have jurisdiction to hear this appeal pursuant to 42 U.S.C. §7607(b) (1982).

II. Standard of Review

Courts have generally accorded substantial deference to the EPA's interpretation of the Clean Air Act Amendments, reasoning that "considerable weight should be accorded to an executive department's construction of a statutory scheme it is entrusted to administer. . . ." *Chevron U.S.A. Inc. v. Natural Resources Defense Council, Inc.*, 467 U.S. 837, 844 [21 ERC 1049] (1984); *see Union Elec. Co. v. EPA*, 427 U.S. 246, 256 [8 ERC 2143] (1976); *Train v. Natural Resources Defense Council, Inc.*, 421 U.S. 60, 75, 87 [7 ERC 1735] (1975); *ASARCO Inc. v. EPA*, 578 F.2d 319, 325 [11 ERC 1129] (D.C. Cir. 1978). This deference with regard to the Clean Air Act follows logically from the highly technical provisions of the Amendments, *Chevron*, 467 U.S. at 848, and is consistent with the Administrative Procedure Act, which provides that agency actions are to be set aside only if they are "arbitrary, capricious, an abuse of discretion, or otherwise not in accordance with law." 5 U.S.C. §706(2).

To be sure, this standard does not give the EPA unbridled discretion to construe the Clean Air Act Amendments free from judicial oversight. We must consider whether the EPA's construction comports with its statutory mandate and Congress' intent in enacting clean air legislation. But we cannot simply substitute our judgment for that of the EPA. Our role has been sharply defined and limited by the Supreme Court:

> When a court reviews an agency's construction of the statute which it administers, it is confronted with two questions. First, always, is the question whether Congress has directly spoken to the precise question at issue. If the intent of Congress is clear, that is the end of the matter; for the court, as well as the agency, must give effect to the unambiguously expressed intent of Congress. If, however, the court determines Congress has not directly addressed the precise question at issue, the court does not simply impose its own construction on the statute, as would be necessary in the absence of an administrative interpretation. Rather, if the statute is silent or ambiguous with respect to the specific issue, the question for the court is whether the agency's answer is based on a permissible construction of the statute.

Chevron, 467 U.S. at 842-43 (footnotes omitted).

Further, we defer even more to an agency's construction of its own regulations. *Lyng v. Payne*, 476 U.S. 926, 939 (1986); *see Wilkins v. Sullivan*, 889 F.2d 135, 139 (7th Cir. 1989); *Homemakers North Shore, Inc. v. Bowen*, 832 F.2d 408, 411 (7th Cir. 1987) (agency construction of its regulations usually upheld). An agency's interpretation must be upheld " 'unless it is plainly erroneous or inconsistent with the regulation.' " *Udall v. Tallman*, 380 U.S. 1, 16-17 (1965) (quoting, in part, *Bowles v. Seminole Rock & Sand Co.*, 325 U.S. 410, 413-14 (1945)). The principle of deference has particular force where, as is the case here, the subject being regulated is technical and complex. *Aluminum Co. of Am. v. Central Lincoln Peoples' Util. Dist.*, 467 U.S. 380, 390 (1984); *Wilkins v. Sullivan*, 889 F.2d at 140; *see also Skidmore v. Swift & Co.*, 323 U.S. 134, 140 (1944) (rulings of agency constitute bodies of experience and informed judgment).

III. Like-Kind Replacement and Modification under the Act

A. The Underlying Statutory Framework

With these principles in mind, we may address the merits. We must first consider whether WEPCO's Port Washington replacement program constitutes a modification under the terms of the controlling statute, 42 U.S.C. section 7411(a)(4). *Cf. Blue Chip Stamps v. Manor Drug Stores*, 421 U.S. 723, 756 (1975) (Powell, J., concurring) ("The starting point in every case involving construction of a statute is the language itself.") Section 7411(a)(4) defines modification as "any physical change . . . which increases the amount of any air pollutant emitted . . . " 42 U.S.C. §7411(a)(4). Both parts of this definition — any physical change and an increase in emissions — must be satisfied before a replacement will be considered a "modification."

1. Physical Change

Certainly under the plain terms of the Act, WEPCO's replacement program constitutes a "physical change." WEPCO proposes to replace rear steam drums on units 2, 3, 4 and 5; each of these steam drums measures 60 feet in length, 50.5 inches in diameter and 5.25 inches in thickness. Clay Memorandum at 4. In addition, WEPCO plans to replace another major component, the air heaters, in units 1-4. To implement this four-year program, WEPCO will need to make the replacements by taking the units successively out of service for nine-month periods. *Id.* These steps clearly amount to a "physical change" in the Port Washington plant. *See* Butler, *New Source Netting In Nonattainment Areas under the Clean Air Act*, 11 Ecology L.Q. 343, 349-50 (1984) ("[T]he new source review requirements are triggered not only whenever an operator builds a new plant, but also whenever the operator *installs or alters a piece of equipment in an existing plant* and thereby increases emissions.") (emphasis supplied).

WEPCO does not dispute that its steam drum and air heater replacements will result in an altered plant. But WEPCO does assert that Congress did not intend for simple equipment replacement to constitute a physical change for purposes of the Clean Air Act's modification provisions:

> The plain meaning of "modify" is "to change or alter" [Webster's New World Dictionary] or "to make basic or fundamental changes in." [Webster's Ninth New Collegiate Dictionary] Reflecting the plain meaning of this term, Congress provided that a facility (1) must undergo a physical or operational "change" before it is evaluated under the modification provision . . . Thus, under the plain meaning of the Act, a unit should not be deemed "modified" as a result of replacement of equipment with equipment similar to that replaced. As in the case of Port Washington, such like-kind replacement does not "change or alter" the design or nature of the facility. Rather, it merely allows the facility to operate again as it had before the specific equipment deteriorated.

Petitioner's Brief at 32—33.

[1] *Chevron* instructs us to rely more on congressional direction and on agency construction (pursuant to congressional delegation) than on glosses found in the dictionary. What WEPCO calls "plain" is anything but plain and takes the definition far beyond the words enacted by Congress. *Chevron*, 467 U.S. at 843-45; *see generally*, R. Anthony, *Report to the Administrative Conference of the United States: Which Agency Interpretations Should Bind the Courts and the Public?* (1989) (explaining *Chevron* approach). Thus, whether the replacement of air heaters and steam drums is a "basic or *fundamental* change" in the Port Washington plant is irrelevant for our purposes, given Congress' directions on the subject: "The term 'modification' means *any* physical change . . ." 42 U.S.C. §7411(a)(4) (emphasis supplied). We follow Congress' definition

of "modification" — not Webster's — when interpreting this term within the context of the Clean Air Act. *Cf. Chevron,* 467 U.S. at 861 ("[T]he meaning of a word must be ascertained in the context of achieving particular objectives. . . .").

Nor can we find any support in the relevant case law for the narrow constructions of "modification" and "physical change" offered by WEPCO. The Supreme Court reported in *Chevron* that Senator Muskie, one of the principal supporters of the Clean Air Act, remarked: "A source . . . is subject to all the nonattainment requirements as a modified source if it makes *any physical change* which increases the amount of any air pollutant. . . ." 467 U.S. at 853 (quoting 123 Cong. Rec. 26847 (1977) (emphasis supplied). And other courts considering the modification provisions of NSPS and PSD have assumed that "any physical change" means precisely that. *See, e.g., National-Southwire Aluminum Co. v. EPA* 838 F.2d 835 [27 ERC 1281] (6th Cir.), *cert. denied,* 109 S.Ct. 390 [28 ERC 1608] (1988) (turning off pollution control equipment constitutes "physical change" and modification); *Alabama Power Co. v. Costle,* 636 F.2d 323, 400 [13 ERC 1993] (D.C. Cir. 1979) ("[T]he term 'modification' is nowhere limited to physical changes exceeding a certain magnitude."); *ASARCO Inc. v. EPA,* 578 F.2d 319, 322 (D.C. Cir. 1978) (NSPS applies to any stationary source that is "physically or operationally changed in such a way that its emission of any air pollutant increases.") (emphasis removed). *Cf. United States v. Narragansett Improvement Co.,* 571 F. Supp. 688, 694-95 [19 ERC 2212] (D.R.I. 1983) (replacement program not modification because, despite physical change, no increase in emissions).

Further, to adopt WEPCO's definition of "physical change" would open vistas of indefinite immunity from the provisions of NSPS and PSD. Were we to hold that the replacement of major generating station systems — including steam drums and air heaters — does not constitute a physical change (and is therefore not a modification), the application of NSPS and PSD to important facilities might be postponed into the indefinite future. There is no reason to believe that such a result was intended by Congress. The Clean Air Act Amendments were enacted to "speed up, expand, and intensify the war against air pollution in the United States with a view to assuring that the air we breathe throughout the Nation is wholesome once again." H.R.Rep.No. 91-1146, 91st Cong., 2d Sess. 1, 1, *reprinted in* 1970 U.S. Code Cong. & Admin. News 5356, 5356. In particular, the permit program established by the 1977 Amendments to the Clean Air Act represented a balance between "the economic interest in permitting capital improvements to continue and the environmental interest in improving air quality." *Chevron,* 467 U.S. at 851. The House echoed this theme in its Committee report: "[The compliance program is designed, in part,] to allow reasonable economic growth to continue in an area while making reasonable further progress to assure attainment of the [pollution-control] standards by a fixed date. . . ." H.R.Rep.No. 294, 95th Cong., 1st Sess. 211, *reprinted in* 1977 U.S. Code Cong & Admin. News 1077, 1290. A too restrictive interpretation of "modification" might upset the economic-environmental balance in unintended ways.

Consistent with its balanced approach, Congress chose not to subject existing plants to the requirements of NSPS and PSD. Members of the House recognized that "[b]uilding control technology into new plants at time of construction will plainly be less costly then [sic] requiring retrofit when pollution control ceilings are reached." H.R.Rep.No. 294, 95th Cong., 1st Sess 185, *reprinted in* 1977 U.S. Code Cong. & Admin. News at 1264. But Congress did not permanently exempt existing plants from these requirements; section 7411(a)(2) provides that existing plants that have been modified are subject to the Clean Air Act programs at issue here. As Judge Boggs, dissenting in *National-Southwire,* reasoned: "The purpose of the 'modification' rule is to ensure that pollution control measures are undertaken when they can be most effective, at the time of new or modified construction. *See* 116 Cong. Rec. 32,918. (remarks of Sen. Cooper), *reprinted in* 1 Senate Committee on Public Works, A Legislative History of the Clean Air Act Amendments of 1970 (1974), at 260." *National-Southwire Aluminum Co. v. EPA,* 838 F.2d 835, 843 (6th Cir.) (Boggs, J., dissenting), *cert. denied,* 109 S.Ct. 390 (1988). Judge Boggs argued that the shutting down of pollution control equipment in an existing plant should not be considered a modification because it would not afford the utility an opportunity for "effective placement of new control technology." *Id.* Here the record is silent on this point (although the point is important). How easy or difficult would be "the effective placement of new control technology" in these renovated units is not clear, but we do know that the project already contemplates replacement of steam drums, air heaters and other components; each unit would, therefore, in any event be shut down for nine months.

Our reading of the phrase "any physical change" is also consistent with another of the basic goals of the 1977 Amendments: technology-forcing. The legislative history suggests and courts have recognized that in passing the Clean Air Act Amendments, Congress intended to stimulate the advancement of pollution control technology. *See, e.g.,* S.Rep.No. 91-1196, 91st Cong., 2d Sess. 17 (1970) ("Standards of performance should provide an incentive for industries to work toward constant improvement in techniques for preventing and controlling emissions from stationary sources. . . ."); *Duquesne Light Co. v. EPA,* 698 F.2d 456, 475 [18 ERC 1489] (D.C. Cir. 1983); *Alabama Power,* 636 F.2d at 372; *ASARCO,* 578 F.2d at 327; *United States v. SCM Corp.,* 667 F.Supp. 1110, 1126-27 [26 ERC 1586] (D. Md. 1987). The development of emissions control systems is not furthered if operators could, without exposure to the standards of the 1977 Amendments, increase production (and pollution) through the extensive replacement of deteriorated generating systems.

2. Increase in Emissions

The controversy involving WEPCO's alleged increase in emissions primarily concerns the regulations, not the statute: WEPCO argues that the EPA's *regulatory* method of measuring emissions is arbitrary and capricious. From a statutory standpoint, however, the modification provisions of the Clean Air Act Amendments are activated once a physical change is coupled with an "increase[ ] [in] the amount of any air pollutant emitted." 42 U.S.C. §7411(a)(4). *See, e.g., United States v. Narragansett Improvement Co.,* 571 F.Supp. at 694. In the case before us, WEPCO does not dispute that its replacement program — intended to enable its deteriorated generators to operate at full capacity — will cause its emissions to increase from their current operating levels. The question for resolution, however, is whether the EPA properly construed its regulations by comparing actual emission rates with so-called "baseline" rates to determine the increase in emissions for NSPS and PSD purposes. We will discuss this subject later; but for purposes of the statutory requirement, we simply observe that the rejuvenated Port Washington plant will produce more emissions after the completion of the renovation project than the operating deteriorated plant produced shortly before the project was undertaken.

B. The EPA's Regulations

Although we have determined that WEPCO's repair and replacement program satisfies the modification provisions of the Clean Air Act Amendments, this is not the end of our inquiry. WEPCO's attack focuses primarily on EPA regulations, which in a number of respects are narrower than the statute. WEPCO argues that the EPA applied its regulations arbitrarily and capriciously to the Port Washington project.

1. Physical Change and the "Routine" Exception

EPA regulations define "modification" as "any physical or operational change to an existing facility which results in an increase in the emission rate to the atmosphere of any pollutant to which a standard applies." 40 C.F.R. §60.14(a) (1988). To a major degree, this definition parallels 42 U.S.C. section 7411(a)(2) and it is unnecessary to repeat the analysis already applied to the statute. *See supra* III(A)(1). However, the EPA has, in addition, used its regulations to exempt a number of activities from the broader definition. The exemption that may be relevant here is accomplished by the following language:

> The following shall not, by themselves, be considered modifications under this part:
>
> (1) Maintenance, repair, and replacement which the Administrator determines to be routine for a source category. . . .

40 C.F.R. §60.14(e) (1988). *See* 40 C.F.R. §52.21(b)(2)(iii). WEPCO relies on this language to argue that, even if its repair and replacement program amounts to a physical change, it was specifically exempted by the regulations.

Again, we accord substantial deference to an agency's interpretation of its own regulations, especially with respect to technical and complex matters. *Lyng v. Payne,* 476 U.S. 926, 939 (1986); *Alumi-*

num Co. of Am. v. Central Lincoln Peoples' Util. Dist., 467 U.S. 380, 390 (1984). In this connection, to determine whether proposed work at a facility is routine, "EPA makes a case-by-case determination by weighing the nature, extent, purpose, frequency, and cost of the work, as well as other relevant factors, to arrive at a common-sense finding." Clay Memorandum at 3. The EPA considered all these factors in determining that the Port Washington project was not routine; first, the EPA observed that the nature and extent of the project was substantial: WEPCO proposed to replace sixty-foot steam drums (in units 2, 3, 4 and 5) and air heaters (in units 1, 2, 3 and 4) during successive nine-month outages at each unit. *Id.* at 4. Certainly, the magnitude of the project (as well as the down-time required to implement it) suggests that it is more than routine.

Further, the EPA points to WEPCO's admission in its application that "[work items] falling into the category of *repetitive maintenance that are normally performed* during scheduled equipment outages ... *are not included in this application.*" Cassidy Letter at 1 (emphasis supplied). This admission suggests that WEPCO at first blush did not regard the repair and replacement project as ordinary or routine.

In addition, the EPA noted that far from being routine, the Port Washington project apparently was unprecedented: "WEPCO did not identify, and EPA did not find, even a single instance of renovation work at any electric utility generating station that approached the Port Washington life extension project in nature, scope or extent." Respondent's Brief at 44; *see* Clay Memorandum at 4 ("[T]his is a highly unusual, if not unprecedented, and costly project."). We surmise, although the record is silent, that the "case of first impression" character of the project may reflect historical practice in the electric utility industry of replacing old plants (at the expiration of their useful lives) with new plants, employing improved technologies and achieving improved efficiencies. This was the typical practice, rather than the mere extension of life of existing plants through massive like-kind replacements. *Cf.* Clay Memorandum at 4 ("[The Port Washington project's] purpose is to completely rehabilitate aging power generating units whose capacity has significantly deteriorated over a period of years, thereby restoring their original capacity and substantially extending the period of their utilization as an alternative to retiring them as they approach the end of their useful physical and economic life.").

WEPCO asks us to overlook the factors outlined in the Clay Memorandum and reverse the EPA primarily on the basis of earlier EPA decisions characterizing certain replacement programs as routine; WEPCO argues that the nature and extent of these "routine" projects parallel those of its Port Washington project. For example, WEPCO presented the EPA with a list of forty air heaters in other plants that had been replaced without triggering NSPS or PSD provisions. Letter from Mark P. Steinberg, Superintendent — Air Quality of WEPCO, to Dale Ziege, Wisconsin Department of Natural Resources (Jan. 11, 1989). But as WEPCO has acknowledged, the plate-type air heaters at issue in the Port Washington project must be replaced *in whole*; in contrast, the forty units where replacement was apparently considered routine contained a Ljungstrom basket or tubular type heater, a type that permits the replacement of the heat transfer surface without requiring the removal of the entire unit. Supplemental Determination at 6-7. Obviously, the precise nature of the physical change is a material factor in determining whether the change is routine, and for this purpose it is important that the subject of past EPA practice be closely comparable with the change under consideration here. *See* Thomas Letter at 3 ("PSD and NSPS applicability determinations are made on a case-by-case basis."). WEPCO has not demonstrated that the EPA's conclusion that the forty other air heater replacements were dissimilar is arbitrary and capricious.[2]

[2] The purpose, frequently and cost of the work also support the EPA's decision here. WEPCO admits that the plans for extensive renovation "represent a *life extension* of the units from their *planned retirement dates*," Cassidy Letter at 2-3 (emphasis supplied), and it recognizes that "the renovation work items included in this application are those that would normally occur only once or twice during a unit's expected life cycle." *Id.* at 1. Indeed, WEPCO reported that it had never previously replaced a steam drum or "header" of comparable size at any of its coal-fired electrical generating facilities. Clay Memorandum at 5. Further, the Port Washington renovation project will cost at least $70.5 million. Letter from John W. Boston, Senior Vice President of WEPCO, to Gary D. McCutchen, Chief New Source Review Section of the EPA, at 4 (May 19, 1988). These factors suggest that the project is not routine.

WEPCO urges that the EPA's conclusions are supported by neither the evidence nor the provisions of the Clean Air Act Amendments. WEPCO reasons that because *any* replacement project will presumably extend the life of a facility, the EPA's reliance on life extension as a factor in denying the routine nature of a project is overbroad. Petitioners' Brief at 44. Although perhaps persuasive on its face, WEPCO's analysis is ultimately wide of the mark. While it is certainly true that the repair of deteriorated equipment will contribute to the useful life of any facility, it does not necessarily follow that the repairs in question would extend the *life expectancy* of the facility. The need for some repairs along the line is a given in determining in the first instance the life expectancy of a plant. WEPCO cannot seriously argue that its units' planned retirement dates of 1992 (units 1 and 2) and 1999 (units 3, 4 and 5) did not take into account at least minor equipment repairs and replacements.[3] And WEPCO concedes that the Port Washington program will *extend* the life expectancy of the plant until 2010. The EPA concluded that the proposed project will increase the life expectancy of the Port Washington facility, and this conclusion was a factor in the finding that the work was not routine. These determinations were not arbitrary and capricious.

Still, WEPCO asserts that the cost, magnitude and nature of its Port Washington project are irrelevant for purposes of the "routine" exception to NSPS and PSD. WEPCO contends that the EPA has already addressed these factors — including the perpetuation of existing sources — through its so-called "reconstruction" rule:

> (a) An existing facility, upon reconstruction, becomes an affected facility [subject to NSPS], irrespective of any change in emission rate.
>
> (b) "Reconstruction" means the replacement of components of an existing facility to such an extent that:
>
> (1) The fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility....

40 C.F.R. §60.15 (1988).[4] *See* United States Environmental Protection Agency, *Electric Utility Steam Generating Units: Background Information for Proposed Particulate Matter Emission Standards* 5-7 (1978). WEPCO believes that, because the air heater replacements will presumably cost less than six percent of a wholly new facility, the reconstruction provisions are not triggered. Therefore, WEPCO argues that the cost and scope of the project are relevant only to a "reconstruction" analysis and are not material for purposes of the routine exception to the modification provisions. Petitioner's Brief at 46.

WEPCO's analysis fails to note, however, the fundamental differences distinguishing the reconstruction and modification provisions. The reconstruction provision applies to any substantial replacement (more than 50% of the cost of a new facility) *even if the replacement causes no subsequent increase in emissions.* In sharp contrast, the modification provisions apply only when a physical change is accompanied *by an increase in emissions.* To argue, therefore, that the reconstruction provision is the *exclusive* determinant of

---

[2] We similarly view supplemental evidence martialled by WEPCO on this point. WEPCO argues that the EPA has treated the replacement of coal pulverizers and regenerator cyclones as routine; however, WEPCO fails to demonstrate the similarities between these units and their heaters and steam drums at issue here. While it is true that some repair and replacement programs are routine, it does not necessarily follow that all such programs are routine. Without more evidence, we are not convinced that the EPA's characterization of the massive Port Washington project as non-routine is inconsistent with its prior rulings.

[3] By WEPCO's own admission, "even a new facility could not operate normally but for a relatively short period of time ... [w]ithout any repair or replacement...." Petitioner's Brief at 44. Because the plants were placed into service between 1935 and 1950 — and because WEPCO acknowledges that the life expectancy of these plants was approximately fifty years — it is clear that WEPCO included minor part repair and replacement in its calculations. Of course, the planned retirement dates appear to be merely estimates and do not seem to be binding.

[4] The reconstruction provisions of the regulations apply only to NSPS; given the existing regulatory framework, the EPA decided that they would not be necessary for PSD. *See* 45 Fed. Reg. 52676, 52703 (1980).

whether the cost, nature and magnitude of a project will require the application of NSPS is to ignore the substantially different objectives of the reconstruction and modification provisions: The reconstruction provision is aimed principally at "discourag[ing] the perpetuation of a facility, instead of replacing it at the end of its useful life with a newly constructed affected facility," *without regard to emissions,* 39 Fed. Reg. 36946, 36948 (1974), while the modification provision applies to *any* physical change, without regard to cost, that causes an increase in emissions. *See, e.g., ASARCO Inc. v. EPA,* 578 F.2d 319 (D.C. Cir. 1978); *United States v. Narragansett Improvement Co.,* 571 F.Supp. 688, 695 (D.R.I. 1983) ("a 'reconstruction' of an existing facility would occur 'irrespective of any change in emission rate' upon the replacement of a 'substantial portion of the existing facility's components.' "). Hence, we cannot agree that the EPA's consideration of the cost, magnitude and nature of the Port Washington project, for purposes of the modification provision of the regulations (and its "routine" exception), is somehow "preempted" by the reconstruction provisions of the regulations. The EPA's examination of these factors, therefore, was not arbitrary or capricious.

2. Increase in Emissions

Thus far, we have not had to address the important differences between the PSD and NSPS programs. At this point, however, the differences become crucial, because each program measures emissions in a fundamentally distinct manner.

a. NSPS Measurements

As previously noted, the EPA's NSPS program is concerned primarily with increases in emission rates, expressed in kilograms per hour of discharged pollutants. 40 C.F.R. §60.14 (1988). The EPA compares the hourly emissions of the unit at its current maximum capacity to its potential emissions at maximum capacity after the change. Clay Memorandum at 9; *see* 40 C.F.R. §60 App. C (1988) (providing complex formulae for determining emission rate change). In this calculation, the agency disregards the unit's maximum *design* capacity; this factor often sheds little light on the unit's *actual current* capacity to produce emissions.[5]

The EPA applied these procedures in examining the generating units at Port Washington. The EPA asked WEPCO to submit figures for the actual operations and emissions of each unit at the Port Washington plant for the years 1978 to 1987; the EPA then relied upon the 1987 figures to calculate the emissions baseline against which post-replacement emissions could be compared. WEPCO, however, challenged the EPA's acceptance of these preliminary baseline figures, arguing that units 1, 2, 3 and 4 were capable of operating at higher rates of production than those calculated by the EPA based upon the 1987 figures. WEPCO conducted five ten-hour tests at each unit to determine its maximum capacity. Upon reviewing the test results, the EPA agreed that units 2 and 3 could be operated at their design capacities, and it revised the baseline levels for these units. The agency concluded that because there would be no increase in production or emissions, NSPS would not apply to these units following the renovation project. Nonetheless, the EPA refused to alter the baseline levels for units 1 and 4, noting that WEPCO's test had not been conducted pursuant to the test protocol as required by the regulations and the Wisconsin State Implementation Plan (units 1 and 4 exceeded certain maximum allowable emission limits). Supplemental Determination at 8–9. Comparing these 1987 baseline levels to the maximum capacity of the plant after renovation, the EPA concluded that the renovation project would be subject to the provisions of NSPS.

WEPCO asks us to overturn the EPA's final ruling that the Port Washington project triggers NSPS. Specifically, WEPCO argues that, by using 1987 figures in determining the emissions baseline, the EPA failed to apply its own regulations: WEPCO asserts that these figures "reflected voluntary decisions by WEPC[O] regarding safety considerations (e.g., the 'zero' rate for Unit 5) and an electricity demand which did not require operation of the units at higher capacities." Petitioner's Brief at 15–16.

[5] Of course, if the unit is currently operating at maximum design capacity, there will be no difference between the measure of emissions at maximum design capacity and at current maximum capacity. Since the units at Port Washington were operating well below maximum design capacity (and unit 5 was completely shut down), that is not the case here.

WEPCO also posits that the EPA's refusal to compare *representative* pre-renovation emissions with *actual* post-renovation emissions is contrary to EPA regulations and amounts to an abuse of agency discretion.[6]

WEPCO's first assertion is easily dismissed. The EPA's choice of the 1987 figures was based entirely upon WEPCO's own data. And, when WEPCO complained that its own data did not reflect WEPCO's pre-renovation capabilities, the EPA permitted WEPCO to conduct new tests (pursuant to 40 C.F.R. §60 App. C (1988)) that eventually resulted in the revision of the baselines for units 2 and 3.

WEPCO's second charge is far more substantial. WEPCO argues that NSPS regulations require the EPA to use a "representative" year in determining a baseline rate of emissions. The EPA disputes this claim, arguing that "[a]s to NSPS, there is no 'representative emissions' concept. . . . Rather . . . the baseline emission rates for units 1–5 are determined by hourly maximum capacity just prior to the renovations.'" Thomas Letter at 5.

WEPCO's interpretation of the regulations, at first blush, seems sensible: since the regulations require that the manual emission tests and continuous monitoring systems be based upon the "representative performance" of the facility, the emission factor test approach must also be based upon "representative performance." 40 C.F.R. §60.14 (1988); *see* 39 Fed. Reg. 36946, 36947 (1974) (explaining provision).[7] Otherwise, the tests might reach inconsistent results, making the rate of emissions entirely dependent upon the type of test used by the facility. Hence, argues WEPCO, the EPA must examine the emission rates during a representative period, not 1987.

[3] WEPCO's analysis, however, relies upon a flawed premise. WEPCO assumes that the phrase "representative performance of the facility" suggests that the EPA must choose a representative year. Read in context, however, the phrase refers generally to all the *conditions of the test,* not specifically to its timing:

[6] As a preliminary matter, we note that WEPCO has not asked us to review the propriety of the NSPS regulations themselves. Indeed, we have no jurisdiction to conduct such an inquiry: 42 U.S.C. section 7607(b)(1) reserves such questions for the United States Court of Appeals for the District of Columbia Circuit. In this case, WEPCO simply requests that we consider whether the EPA properly applied these regulations to the Port Washington generating units. We have jurisdiction to undertake such an inquiry. 42 U.S.C. §7607(b)(1).

[7] The regulations themselves provide, in part:

(a) . . . any physical or operational change to an existing facility which results in an increase in the emission rate to the atmosphere of any pollutant to which a standard applies shall be considered a modification. . . .

(b) Emission rate shall be expressed as kg/hr of any pollutant discharged into the atmosphere for which a standard is applicable. The Administrator shall use the following to determine the emission rate:

(1) Emission factors as specified in the latest issue of "Compilation of Air Pollutant Emission Factors," EPA Publication No. AP-42, or other emission factors determined by the Administrator to be superior to AP-42 emission factors, in cases where utilization of emission factors demonstrate that the emission level resulting from the physical or operational change will either clearly increase or clearly not increase.

(2) Material balances, continuous monitor data, or manual emission tests in cases where utilization of emission factors as referenced in paragraph (b)(1) of this section does not demonstrate to the Administrator's satisfaction whether the emission level resulting from the physical or operational change will either clearly increase or clearly not increase, or where an owner or operator demonstrates to the Administrator's satisfaction that there are reasonable grounds to dispute the result obtained by the Administrator utilizing emission factors as referenced in paragraph (b)(1) of this section. When the emission rate is based on results from manual emission tests or continuous monitoring systems, the procedures specified in Appendix C of this part shall be used to determine whether an increase in emission rate has occurred. Tests shall be conducted under such conditions as the Administrator shall specify to the owner or operator based on representative performance of the facility. At least three valid test runs must be conducted before and at least three after the physical or operational change. All operating parameters which may affect emissions must be held constant to the maximum feasible degree for all test runs.

40 C.F.R. §60.14 (1988).

[8] The emission factor test is the only technique that can *predict* emission rates after renovations. Because the determination at issue here must be made before the renovations are undertaken, the EPA relied on this test in evaluating the Port Washington project.

> Tests shall be conducted under such conditions as the Administrator shall specify to the owner or operator based on representative performance of the facility. At least three valid test runs must be conducted before and at least three after the physical or operational change. All operating parameters which may affect emissions must be held constant to the maximum feasible degree for all test runs.

40 C.F.R. §60.14(b)(2) (1988). *Compare* 40 C.F.R. §52.21(b)(21)(ii) (1988) (PSD program) ("The Administrator shall allow the use of a *different time period* upon a determination *that it is more representative* of normal source operation.") (emphasis supplied). Put simply, section 60.14 ensures that the operator will not doctor testing conditions to produce favorable emission results. The EPA's explanation of its regulations, which of course is given deference, supports this interpretation: "According to the proposed regulation, each set of emission tests (using manual tests or continuous monitors) conducted before and after a physical or operational change would consist of at least three runs, *and would be conducted under representative operating conditions.*" 39 Fed. Reg. 36946, 36947 (1974) (emphasis supplied). WEPCO has not argued that it conducted its own tests under unrepresentative conditions, nor has it challenged any other part of the test protocol.[9] And WEPCO does not claim that the tests were conducted during a period of operations that substantially differed from the normal operations of the deteriorated Port Washington plant. Further, the fact that the EPA permitted WEPCO to conduct additional emissions tests on the units (during which, presumably, WEPCO could maintain representative operating conditions) undermines WEPCO's assertion that the regulations were applied arbitrarily or capriciously.

b. PSD Measurements

Unlike NSPS, PSD is concerned with changes in *total annual emissions,* expressed in tons per year. The PSD regulations require preconstruction review of the construction or modification of major emitting facilities. These regulations define their key term — "major modification" — as "any physical change in or change in the method of operation of a major stationary source that would result in a significant[10] net emissions increase of any pollutant subject to regulation under the Act." 40 C.F.R. §52.21(b)(2)(i) (1988) (footnote supplied).

Here the question is whether WEPCO's renovation project will result in "a significant net emissions increase" so as to trigger the "major modification" provision of the regulations and, as a result, PSD. To determine whether the project would result in an emissions increase, the EPA compared actual pre-renovation emissions with potential post-renovation emissions at the Port Washington plant. Specifically, the EPA first examined the two-year period of 1983 through 1984 as the pre-renovation baseline period, pursuant to 40 C.F.R. section 52.21(b)(21)(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 precedes the particular date and which is representative of normal source operation. The Administrator shall allow the use of a different time period upon a determination that it is more representative of normal source operation.* Actual emissions shall be calculated using the unit's actual operating hours, production rates, and types of materials processed, stored, or combusted during the selected time period.

40 C.F.R. §52.21(b)(21)(ii) (1988) (emphasis supplied). Because Administrator

[9] WEPCO does assert that the EPA improperly examined only the lowest hourly capacity achieved during the test periods. Even if the EPA had accepted the highest capacity tests, however, the rate of emissions of units 1, 4 and 5 still would have subjected those units to NSPS after the renovation. Further, the EPA acknowledges that there will be no difference between the rate of emissions of units 2 and 3 before and after the renovation, regardless of the chosen capacity level. *See* Letter from Walt Stevenson to Jack Farmer (Jan. 5, 1989) (summarizing Port Washington capacity tests). We therefore need not consider whether the Administrator may rely upon the lowest capacity level.

[10] The regulations define "significant" in terms of threshold emissions increases of individual pollutants: for example, an increase of 40 tons per year of nitrogen oxides is a "significant" net emissions increase. *See* 40 C.F.R. §52.21(b)(23) (1988).

Thomas determined that the discovery of cracks in the rear steam drums led to a more recent "source curtailment," he relied upon the data from earlier years, 1983 and 1984, as the baseline to determine whether the renovation would cause an increase in emissions. Thomas Letter at 5. WEPCO does not challenge this component of the EPA's calculation.

Second, the EPA calculated the actual emissions of the plant *following* completion of the project. Generally, in order to apply PSD, the regulations require the EPA to find an "increase in *actual emissions* from a particular physical change or change in method of operation." 40 C.F.R. §52.21(b)(3)(i)(*a*) (1988) (emphasis supplied). The EPA reasoned, however, that because the source "ha[d] not yet begun operations following the renovation, 'actual emissions' following the renovation [were] deemed to be the source's 'potential to emit.'" Clay Memorandum at 7. In support of its reliance on WEPCO's potential to emit, the EPA pointed to the regulations: "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." 40 C.F.R. §52.21(b)(21)(iv) (1988).

WEPCO objects strenuously, and with good reason. In calculating the plant's post-renovation potential to emit, the EPA bases its figures on round-the-clock operations (24 hours per day, 365 days per year) because WEPCO *could potentially* operate its facility continuously, despite the fact that WEPCO has never done so in the past. And the EPA has admitted that it "assumed that emissions increases at Port Washington would come not from an increase in emission rate, but rather from increases in production rate or hours of operation." Supplemental Determination at 9; *see* Clay Memorandum at 7-8. The EPA responds that WEPCO can avoid these maximum calculations simply by consenting to federally enforceable restrictions on production rates and hours of operation, but WEPCO declines to do so. Clay Memorandum at 8; *see* 40 C.F.R. §§52.21(b)(4), 52.21(b)(16) (1988). Thus, argues the EPA, it has no choice but to assume that the plant will be operated continuously.[11]

The first issue to be addressed is whether the EPA properly invoked the "potential to emit" concept in calculating the emissions increase. As explained above, the PSD regulations state that the EPA may rely upon a facility's potential to emit if the unit "has not *begun normal operations* on the particular date." 40 C.F.R. §52.21(b)(21)(iv) (1988) (emphasis supplied). WEPCO argues that this phrase should be interpreted to include only those units that have never been in operation, while the EPA urges that the phrase can be applied to both new and modified units.

The regulatory history of this phrase sheds little light on its proper interpretation. The EPA argues that it has always interpreted this phrase to include modified units; it asserts that its formulae for determining emissions increases have consistently assumed that "new or *modified units*" would be deemed to operate at maximum physical or federally enforceable levels. 45 Fed. Reg. 52676, 52718 (1980) (emphasis supplied). But the EPA's analysis here seems circular: in order to demonstrate that the Port Washington like-kind replacement project constitutes a modification, the EPA applies the potential to emit concept (to show an increase in emissions). And in order to apply the potential to emit concept to like-kind replacement, the EPA assumes that the plant is a "modified" unit. Although we accord great deference to an agency construing the statute it administers, *Chevron,* 467 U.S. at 844, and even more deference to an agency interpreting its own complex regulations, *Aluminum Co. of Am. v. Central Lincoln Peoples' Util. Dist.,* 467 U.S. at 390, we cannot defer to agency interpretations that, as applied here, appear to assume what they seek to prove.[12]

[11] Despite WEPCO's protestations, we note initially that the EPA's refusal to apply the "production rate/hours of operation" exclusion was proper. 40 C.F.R. §52.21(b)(2)(iii)(*f*) (1988). This exclusion — which states that "[a] physical change or change in the method of operation shall not include . . . [a]n increase in the hours of operation or in the production rate," *id.* — was provided to allow facilities to take advantage of fluctuating market conditions, not construction or modification activity. *See* 45 Fed. Reg. 52676, 52704 (1980).

[12] In a supplemental filing pursuant to Seventh Circuit Rule 28(j), the EPA intimates that the First Circuit's recent decision in *Puerto Rican Cement Co. v. EPA,* 889 F.2d 292 (30 ERC 1650) (1st Cir. 1989), permits the use of the potential to emit concept in similar circumstances. However, unlike the case at issue here, *Puerto Rican Cement* involved the construction of a *new* emissions unit at an existing source. Further, the First Circuit distinguished its

We are also troubled by the EPA's assumption of continuous operations in calculating potential to emit at the Port Washington plant. Although we agree that the EPA cannot reasonably rely on a utility's own unenforceable estimates of its annual emissions,[13] we find no support in the regulations for the EPA's decision wholly to disregard past operating conditions at the plant. Indeed, *Alabama Power Co. v. Costle*, 636 F.2d 323 (D.C. Cir. 1979), which contributes importantly to the EPA's current PSD program, suggests otherwise. There, the D.C. Circuit held, in part, that the EPA must "take[] into account the anticipated functioning of the air pollution control equipment designed into the facility" when calculating the facility's potential to emit. *Id.* at 353. More important for our purposes, however, was the court's discussion of a unit's potential to emit:

> If the source has no actual emissions because it has yet to commence operating, its hypothetical, projected emissions are included in the baseline. *If, however, the source is an established operation, a more realistic assessment of its impact on ambient air quality levels is possible, and thus is directed.*

Id. at 379 (emphasis supplied). The district court in *United States v. Louisiana-Pacific Corp.*, 682 F.Supp. 1141 [27 ERC 1621] (D. Colo. 1988), relying on *Alabama Power*, recently reached the same conclusion:

> The broad holding of *Alabama Power* is that potential to emit does not refer to the maximum emissions that can be generated by a source hypothesizing the worst conceivable operation. Rather, the concept contemplates the maximum emissions that can be generated while operating the source as it is intended to be operated and as it is normally operated. Of course, it is *possible* that a source *could* be operated without the control equipment designed into it or that a Konus heater *could* be operated so badly that the fire would go out. Yet, *Alabama Power* stands for the proposition that hypothesizing the worst possible emissions from the worst possible operation is the wrong way to calculate potential to emit.

Id. at 1158.

[4] In sum, we certainly do not suggest that the EPA may never subject replaced units to the potential to emit concept under its regulations. The EPA may, if it wishes, undertake notice and comment procedures to apply the potential to emit concept to like-kind replacement. *See* 42 U.S.C. §7607(d). But existing regulations do not seem to us to support such an application. We therefore believe that the EPA's reliance on an assumed continuous operation as a basis for finding an emissions increase is not properly supported. The EPA's determination that there has been a major modification for PSD purposes must be set aside.[14]

IV. Fuel Switching

The final significant dispute in this case involves fuel switching. WEPCO proposed to the EPA that its "replacement project combined with an enforceable fuel switch would not 'result[] in an increase in the [sulfur dioxide and particulate matter] emission rate[s]' from those units." Petitioner's Brief at 50

holding from controversies having something in common with the one before us.

> One can imagine circumstances that might test the reasonableness of EPA's regulation. An electricity company, for example, might wish to replace a peak load generator — one that operates only a few days per year — with a new peak load generator that the firm could, but almost certainly will not, operate every day. . . . Whatever the arguments about the "irrationality" of EPA's interpretation in such circumstances, however, those circumstances are not present here.

Id. at 297–98.

[13] The EPA argues that WEPCO can avoid the presumption of continuous operations simply by consenting to federally enforceable emission limits. However, the EPA has not brought to our attention a clear regulatory basis for its conclusion that the provision of this alternative justifies the assumption of continuous operation if the utility refuses to consent. And WEPCO may have legitimate reasons for declining to submit to federally enforceable emission limits: "[U]ncertainties about the precise shape of future electricity peak demand might make the firm hesitate to promise EPA it will *never* increase actual emissions. . . ." *Puerto Rican Cement Co. v. EPA*, 889 F.2d 292, 298 (1st Cir. 1989).

[14] It appears that WEPCO never submitted pollutant-specific data to the EPA. Clay Memorandum at 7-8. Consequently, the EPA could not, at the time the matter was before it, conclude whether the renovated plant would cause a significant net emissions increase if it were operated under present hours and conditions. WEPCO should make such data available so that the EPA can determine on that basis whether the Port Washington plant will be subject to the PSD program.

(brackets in original); *see* 40 C.F.R. §60.14(a) (1988). Nonetheless, the EPA refused to permit WEPCO to utilize lower sulfur coal instead of implementing pollution control technologies to prevent an increase in emissions. The EPA explained that "the statute reflects a basic political decision that fossil fuel-fired sources not rely only on natural occurring less-polluting fuels to comply with the NSPS. Instead, Congress declared that compliance must depend in part upon the application of flue gas treatment or other pollution control technologies." Supplemental Determination at 10. Further, the EPA pointed to 40 C.F.R. section 60.14(b)(2) (1988), which requires that "operating parameters" — including fuel and raw materials — must be held constant in measuring emissions before an after renovations to determine whether the utility has undertaken a modification. WEPCO disputes the EPA's interpretation of the relevant provisions of the Clean Air Act Amendments.

[5] Consistent with the Supreme Court's approach in *Chevron*, we first examine whether the statute evinces a clear congressional intent on the matter. We believe it does. Although the plan language of 42 U.S.C. section 7411 does not resolve the issue, the relevant legislative history provides ample support for the EPA's position. The House Conference Report, for example, states:

> The agreement requires (1) that the standards of performance for fossil fuel-fired boilers be substantially upgraded to require the use of the best technological system of continuous emission reduction and *to preclude use of untreated low sulfur coal alone as a means of compliance;* . . . (3) that for fossil fuel-fired sources, the new source performance standards must be comprised of both a standard of performance for emissions and an enforceable requirement for a percentage reduction in pollution from untreated fuel.

H.R. Rep. No. 564, 95th Cong., 1st Sess. 130, *reprinted in* 1977 U.S. Code Cong. & Admin. News 1077, 1510 (emphasis supplied). In addition, passages from the congressional debates reflect Congress' refusal to allow stationary sources to substitute low sulfur fuels to avoid a requirement of pollution control technology. *See, e.g.*, III Senate Committee on Environment & Public Works, *A Legislative History of the Clean Air Act Amendments of 1977*, at 323, 353 (1978) (disapproving substitution of low sulfur coal for pollution control technology); IV Senate Committee on Environment & Public Works, *supra*, at 2653 (same). In these reports, Congress reasoned that the Administrator's *previous* standards — which had allowed fuel switching in lieu of pollution control technology — directly conflicted with the purposes of the NSPS program:

> 1. The standards give a competitive advantage to those States with cheaper low-sulfur coal and create a disadvantage for Midwestern and Eastern States where predominantly higher sulfur coals are available;
>
> 2. These standards do not provide for maximum practicable emission reduction using locally available fuels, and therefore do not maximize potential for long-term growth;
>
> 3. These standards do not help to expand the energy resources (that is, higher sulfur coal) that could be burned in compliance with emission limits as intended;
>
> 4. These standards aggravate compliance problems for existing coal-burning stationary sources which cannot retrofit and which must compete with larger, new sources for low-sulfur coal;
>
> 5. These standards increase the risk of early plant shutdowns by existing plants (for the reasons stated above), with greater risk of unemployment; and
>
> 6. These standards operate as a disincentive to the improvement of technology of new sources, since untreated fuels could be burned instead of using such new, more effective technology.

III Senate Committee on Environment & Public Works, *supra*, at 323. These purposes, reflecting technological and political choices, demonstrate that Congress rejected fuel switching as a method of avoiding the impact of NSPS. We believe Congress left us no choice on this issue.

V. CONCLUSION

In an era of increasing environmental concern, Congress enacted the Clean Air Act to "speed up, expand, and intensify the war against air pollution in the United States with a view to assuring that the air we breathe throughout the Nation is wholesome once again." H.R. Rep. No. 1146, 91st Cong., 2d Sess. 1, 1, 1970 U.S. Code Cong. & Admin. News 5356, 5356. The EPA is entitled to substantial deference in interpreting the technical provisions of the Act and its own regulations. We cannot grant deference, however, where the EPA has attempted to implement the Act's lofty goals in contravention of its own statutory regime. We therefore affirm in part and vacate in part, remanding the cause to the EPA for further proceedings not inconsistent with this opinion.

EXHIBIT C

September 9, 1988 Memorandum
from Don R. Clay to David A. Kee

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
WASHINGTON, D.C. 20460

SEP 9 1988

OFFICE OF
AIR AND RADIATION

MEMORANDUM

SUBJECT: Applicability of Prevention of Significant Deterioration (PSD) and New Source Performance Standards (NSPS) Requirements to the Wisconsin Electric Power Company (WEPCO) Port Washington Life Extension Project

FROM: Don R. Clay, Acting Assistant Administrator for Air and Radiation (ANR-443)

TO: David A. Kee, Director
Air and Radiation Division, Region V

This is in further response to your March 25, 1988 memorandum requesting guidance on PSD applicability regarding the proposed renovation of the Port Washington Power Plant by the WEPCO. I have also addressed the question whether the renovations proposed for this facility would subject the individual units to Subpart Da of the NSPS.

Based on the information presented in your memorandum, subsequent written information received from WEPCO, information provided by the State of Wisconsin, and other information contained in the Environmental Protection Agency's (EPA's) files on this matter, I have concluded that, as proposed, this renovation project would not come within the PSD and NSPS exclusions for routine maintenance, repair, and replacement, nor the exclusions for increases in production rate or hours of operation. It also appears that the project would increase emissions within the meaning of these two programs. Thus, the renovation project likely would be subject to PSD review as a major modification of an existing stationary source and that the renovations proposed for units 1-5 at this facility probably would subject the individual units to Subpart Da of the NSPS as a modification. However, WEPCO has not yet requested EPA to make an applicability determination. In any case, it would not be possible to make final applicability determinations at this point, for three basic reasons.

First, EPA must be supplied sufficient data regarding the various pollutants emitted by the Port Washington facilities to determine, on a pollutant-specific basis, how the proposed renovations would affect emissions levels. Second, WEPCO might avoid both PSD and NSPS applicability by adding or enhancing pollution control equipment, or in the case of PSD, restricting operations below maximum potential such that the emissions increases necessary to trigger applicability would not occur. The WEPCO should discuss its plans in this regard with EPA. Third, regarding NSPS applicability to unit 1, additional information is necessary to determine whether a physical or operational change would occur.

Thus, although this memorandum will serve to answer many of the questions necessary to reaching final determinations, you should advise WEPCO that ultimately applicability depends upon changes in emissions after the renovations and whether the company decides to take the steps which would enable it to lawfully avoid coverage. Also, NSPS coverage of unit 1 can only be determined after an evaluation of the additional information regarding the work to be performed. In addition, as to NSPS, WEPCO should be advised to submit a formal request pursuant to 40 CFR 60.5 if it desires a final applicability determination.

As the need for further factual development here suggests, determinations of PSD and NSPS applicability are fact-specific, and must be made on a case-by-case basis. This memorandum provides a framework for analyzing the proposed changes at Port Washington and gives EPA's views on relevant issues of legal interpretation. It should also be useful in assessing other so-called "life extension" projects in the future. However, any such project would need to be reviewed in light of all the facts and circumstances particular to it. Thus, a final decision regarding PSD and NSPS applicability here would not necessarily be determinative of coverage as to other life extension projects.

If you have any further questions regarding the discussion or conclusions in this memorandum, please have your staff contact David Solomon of the New Source Review Section at FTS 629-5375.

I. Background

As mentioned in your March 25 request, the five coal-fired units at Port Washington began operation in 1935, 1943, 1948, 1949, and 1950, respectively. Each unit was initially rated at 80 megawatts electrical output capacity. In recent years, however, the performance of the units began to deteriorate due to age-related degradation of the physical plant. In particular, inspections performed by a WEPCO consultant in 1984 revealed extensive cracks originating from the internal surfaces of the rear steam drums and boiler bank boreholes in units 2, 3, 4, and 5, creating significant safety concerns. Because of these safety concerns and other age-related problems, in 1985 the operating levels of units 2, 3, and 4 were reduced, and unit 5 was removed from service. As a result of the plant's deteriorating condition, the maximum rated physical capacities of units 1, 2, 3, and 4 at this time are 45, 65, 75, and 55 megawatts, respectively.

The life extension project includes extensive capital improvements to the common facilities and each of the individual units, including replacement of the rear steam drum in units 2, 3, 4, and 5. The renovation work will restore the physical and operational capability of each unit to its original 80 megawatt nameplate capacity, and extend the useful life of the units well beyond the planned retirement dates that would otherwise apply. Upon completion of the project, WEPCO intends to substantially increase the actual operations at the Port Washington plant.

II. PSD Applicability

The life extension project at Port Washington is subject to preconstruction review and permitting under the Act's PSD provisions if it is a "major modification" within the meaning of the Act and EPA's regulations. The PSD regulations at 40 CFR 52.21 govern this determination because Wisconsin has been delegated PSD permitting authority under the provisions of 52.21(u). The definition of "major modification" in 52.21(b)(2)(i) requires an analysis of several factors. These factors may be grouped under two general questions. Will the work entail a "physical change in or change in the method of operation of a major stationary source"? If so, will the change "result in a significant net emissions increase of any pollutant subject to regulation under the Act" [see 52.21(b)(2)(i)]? The Port Washington facility is an existing major stationary source because it emits well in excess of the PSD threshold amount for several pollutants.

A. Physical Change or Change in the Method of Operation

This requirement of a major modification is satisfied if either a physical or operational change would occur.

1. Physical Change

The renovation work called for under the proposed life extension project at Port Washington would constitute a "physical change" at a major stationary source. The clear intent of the PSD regulations is to construe the term "physical change" very broadly, to cover virtually any significant alteration to an existing plant. This wide reach is demonstrated by the very narrow exclusion provided in the regulations: other than certain uses of alternate fuels not relevant here, only "routine maintenance, repair and replacement" is excluded from the definition of physical change [see 52.21(b)(2)(iii)(a)].

In determining whether proposed work at an existing facility is "routine," EPA makes a case-by-case determination by weighing the nature, extent, purpose, frequency, and cost of the work, as well as other relevant factors, to arrive at a common-sense finding. In this case, all of these factors suggest that the work required under WEPCO's life extension project appears not to be "routine." The available information indicates that the work proposed at Port Washington is far from being a regular, customary, or standard undertaking for the purpose of maintaining the plant in its present condition. Rather, this is a highly unusual, if not unprecedented, and costly project. Its purpose is to completely rehabilitate aging power generating units whose capacity has significantly deteriorated over a period of years, thereby restoring their original capacity and substantially extending the period of their utilization as an alternative to retiring them as they approach the end of their useful physical and economic life. The most important factors that would support these conclusions are outlined below.

a. The project would involve the replacement of numerous major components. The information submitted by WEPCO shows that the company intends to replace several components that are essential to the operation of the Port Washington plant. In particular, as noted above, WEPCO would replace the rear steam drums on the boilers at units 2, 3, 4, and 5. According to WEPCO, these steam drums are a type of "header" for the collection and distribution of steam and/or water within the boilers. They measure 60 feet long, 50.5 inches in diameter, and 5.25 inches thick, and their replacement is necessary to continue operation of the units in a safe condition. In addition, at each of the emissions units, WEPCO plans to repair or replace several other integral components, including replacement of the air heaters at units 1, 2, 3, and 4. The WEPCO also plans to renovate major mechanical and electrical auxiliary systems and common plant support facilities. The WEPCO intends to perform the work over a 4-year period, utilizing successive 9-month outages at each unit.

In its July 8, 1987 application for authority to renovate to the Public Service Commission of Wisconsin (PSC), WEPCO described the life extension project and explained its purpose and necessity. The WEPCO took care to distinguish the proposed renovation work from routine maintenance that did not require PSC approval, explaining that:

> . . . [work items] falling into the category of repetitive maintenance that are normally performed during scheduled equipment outages do not require specific commission approval and, accordingly, are not included in this application.

Thus, WEPCO's own earlier characterization of this project supports a finding that the planned renovations are not routine.

b. The purpose of the project is to significantly enhance the present efficiency and capacity of the plant and substantially extend its useful economic life. In its application to the PSC, WEPCO pointed out that due to age-related deterioration, total plant capability had declined by 40 percent. The company noted that the currently planned retirement dates for the Port Washington units, as set forth in its Advance Plan filed with the State, ranged from 1992 to 1999. However, WEPCO asserted that "extensive renovation of the five units and the plant common facilities is needed if operation of the plant is to be continued." In any event, WEPCO stated that the renovation work would allow the Port Washington plant to generate power at its designed capacity until the year 2010, and thus "represents a life extension of the units."

In contrast, in its July 29, 1988 letter to EPA headquarters (pages 9-13), WEPCO characterized the renovation work as the timely, routine correction of equipment problems--principally, the steam drum cracks. However, the information presented leads to the conclusion that this is not the case. While replacement of the steam drums is necessary to restore lost generating capacity, that is not the only work proposed to be done. Based upon maximum capacity figures for past years, it appears that the units had experienced deterioration in physical generating capacity even prior to the discovery of the steam drum cracks in 1984. Thus, WEPCO proposes a wide-ranging project encompassing a broad array of tasks that would not only correct the steam drum problem, but correct other age-related deterioration that is essentially independent of the steam drums. Such other work (e.g., replacement of air handlers) apparently is also necessary as a practical matter to restore original nameplate capacity. Thus, it appears that even if WEPCO had undertaken this renovation work immediately following discovery of the steam drum cracks, it would have been proper to characterize the proposed work as a nonroutine life extension project.[1]

c. The work called for under the project is rarely, if ever, performed. The WEPCO's application to the PSC asserted that the work to be performed under the life extension project was not frequently done:

> Generally, the renovation work items included in this application are those that would normally occur only once or twice during a unit's expected life cycle.

The EPA asked WEPCO to submit information regarding the frequency of replacement of steam drums, the largest category of work item called for under the project. WEPCO reported that to date, no steam drums have ever been replaced at any of its coal-fired electrical generating facilities. WEPCO did point out that it had replaced other "headers" comparable in design pressure and function. However, the largest of these was 16 inches in

---

[1]It is important to note in this regard that not all renovation, repair, or "life extension" projects would properly be characterized as modifications potentially subject to PSD and NSPS. For example, nonroutine repairs to correct unexpected equipment outages, even of major components such as steam drums, would not be subject to NSPS if they did not increase the maximum capacity of the affected facility as it existed prior to the outage. Conversely, undertaking a program of repair and maintenance properly characterized as routine would not subject a facility to the Act's requirements.

diameter, and EPA does not believe that they are comparable in diameter, wall thickness, function, or importance to the rear steam drums at Port Washington.[2]

d. The work called for under the project is costly, both in relative and absolute terms. The latest information supplied by WEPCO is that the renovation work at Port Washington will cost $87.5 million, of which at least $45.6 million is designated as capital costs.[3] The WEPCO reports that, in terms of annualized costs, the renovation project will cost $7.8 million, as compared to $51.6 million for a new 400 megawatt plant. Thus, renovation costs represent approximately 15 percent of replacements costs.

2. Change in the Method of Operation

The renovation work at Port Washington would not constitute a "change in the method of operation" within the meaning of the PSD regulations. However, it is clear that the "physical change" and "operational change" components of the "major modification" definition are discrete and independent. Thus, as explained below, PSD still applies if there is a physical change that will significantly increase net emissions.

In addition, the regulations exclude from the definition of physical or operational change "an increase in the hours of operation or in the production rate" [see 40 CFR 52.21(b)(2)(iii)(f)]. The preamble to the rule [45 FR 52676, 52704 (August 7, 1980)], makes it clear that this exclusion is intended to allow a company to lawfully increase emissions through a simple change in hours or rate of operation up to its potential to emit (unless already subject

---

[2]The WEPCO's July 29, 1988 letter to EPA stated (on page 13) that after further investigation, the company "learned of several examples" of steam drum failure and replacement. However, WEPCO provides no further details, other than noting that in one instance, the drum failed during initial testing and was replaced. Replacement of a failed component at a new facility presumably would not increase emissions from the facility, and probably would be viewed as routine if the alternative was to forego operation of that new facility. Under such circumstances, it is unlikely that the replacement would trigger the Act's requirements.

[3]The WEPCO's July 8, 1987 application to the PSC included a project cost estimate of $83.9 million, of which $45.6 million was designated as capital costs. A more recent cost estimate provided to EPA by WEPCO indicates that several work items are now deemed unnecessary, such that the cost of the original project is now estimated at $70.5 million. However, all but $89,000 of these reductions are designated as "maintenance" items. The recent submission also relates that the scope of the original project has now been expanded to include flue gas conditioning equipment and associated air heater work costing approximately $17 million. Although WEPCO has not broken down these additional costs into capital and maintenance (or "expense") expenditures, it would appear that most, if not all, of this additional work would be classified as capital costs. Thus, it is highly likely that actual capital costs would be significantly higher than $45.6 million.

to any federally enforceable limit) without having to obtain a PSD permit. Thus, emissions increases at Port Washington associated with increased operations would not, standing alone, subject WEPCO to PSD requirements. However, as discussed in greater detail below, the exclusion for increases in hours of operation or production rate does not take the project beyond the reach of PSD coverage if those increases do not stand alone but rather are associated with non-excluded physical or operational changes.

In its March 17, 1988 letter to Region V and its July 29, 1988 letter to EPA Headquarters, WEPCO asserted that the exclusion for increases in operational hours or production rate also would serve to render PSD review not applicable to the renovation work proposed at Port Washington because the project's purpose was to restore the original design capacity of 80 megawatts per unit, but not to exceed that level. However, a plant's original design capacity is irrelevant to a determination of PSD applicability.

B. Significant Net Emissions Increase

Under the PSD regulations, whether the life extension project at Port Washington would result in a "significant net emissions increase" depends on a comparison between the "actual emissions" before and after the physical changes resulting from the renovation work. Where, as here, the source has not yet begun operations following the renovation, "actual emissions" following the renovation are deemed to be the source's "potential to emit" [see 40 CFR 52.21(b)(21)(iv)]. Apparently, there would be a "significant net emissions increase" within the meaning of the PSD regulations as a result of the proposed renovations as currently planned, because potential emissions after the project--reflecting the restoration of 80 megawatt capacity at each unit--would greatly exceed representative actual emissions prior to the physical changes. (The fact that the project is intended to restore the plant's original design capacity is irrelevant to that calculation.)[4] If this is so, the project would be a "major modification" subject to PSD review. However, PSD applies on a pollutant-specific basis, and EPA has not been furnished with adequate data regarding the impact of the proposed renovations on the various pollutants to determine whether a significant net emissions increase would indeed occur for any pollutant. Such data must be provided before EPA can make a final determination of PSD applicability.

[4]The WEPCO also contends (July 29, 1988 letter, page 35) that EPA should instead compare representative actual emissions prior to the change with "projected" actual emissions after the renovations. The PSD regulations provide no support for this view. Where, as here, a source is not currently subject to a PSD permit containing operational limitations, EPA must presume that the source will operate at its maximum capacity and, hence, its maximum potential to emit. However, as discussed below, a source is entitled to reduce its potential to emit by embodying its "projections" of future emissions in federally enforceable restrictions on its operations that may serve to lawfully avoid PSD review.

It is important to note in this regard that WEPCO, at its option, could "net out" of PSD review by accepting federally enforceable restrictions on its potential to emit after the renovation. This could occur through enhancement of existing pollution control equipment, addition of new equipment, acceptance of federally enforceable operational restrictions, or some combination of these measures, limiting potential emissions to a level not significantly greater than representative actual emissions prior to the renovations. Theoretically, WEPCO could minimize the needed restrictions on its potential to emit following the renovations if it could show that some period other than the most recent two years is "more representative of normal source operation" [see 52.21(b)(21)(ii)]. (Obviously, such a showing would be most important with respect to unit 5, because it has been shut down and has had zero emissions since 1985.) Since these matters are within WEPCO's control, you should advise the company to enter discussions with Region V and Wisconsin, as appropriate, if WEPCO desires to "net out" of PSD review.

The WEPCO also argued in its July 29, 1988 letter, at pages 33-41, that even if EPA is correct that the Port Washington life extension project would involve physical changes within the meaning of the PSD regulations, any emissions increases would be due to increased production rates or hours of operation rather than higher emissions per unit of production. Therefore, WEPCO contends that these increases should be excluded from consideration in determining whether a net significant emissions increase and, hence, a major modification, would occur. The WEPCO is incorrect in this regard.

As noted above, the exclusions cited by WEPCO are intended to apply where a source increases emissions by simply combusting a larger amount of fuel, or processing a larger amount of raw materials during a given time period, or by expanding its hours of operation "to take advantage of favorable market conditions" (see 45 FR 52704). In this instance, however, it is obvious that WEPCO's plans to increase production rate or hours of operation are inextricably intertwined with the physical changes planned under the life extension project. Absent the extensive renovations proposed at Port Washington, WEPCO would have little market incentive to, and in part would be physically unable to, increase operations at these aged and deteriorated facilities which, absent the renovations, would likely be retired from service in the near future. Thus, WEPCO's plans call for precisely the type of "change in hours or rate or operation that would disturb a prior assessment of a source's environmental impact [and] should have to undergo [PSD review] scrutiny" (see 45 FR 52704). Conversely, accepting WEPCO's interpretation of the major modification regulations would serve to exclude from consideration all physical or operational changes except those which cause increased emissions per unit of production. Clearly, EPA never intended this result. It would allow, through substantial capital investment, significant expansion of the pollution-emitting capacity and longevity of major industrial facilities without PSD review of the impacts on air quality and opportunities for future economic growth.

C. Baseline Date

The November 9, 1987 letter from the Wisconsin Department of Natural Resources to Region V asked whether a complete March 28, 1986 PSD permit application for certain work at Port Washington triggered the PSD baseline date, despite the fact that the permit was never issued. The answer to this question is yes. Baseline dates are triggered by the first complete application and remain in effect regardless of whether the application is revised or withdrawn, or whether the permit is finally issued and the source constructed or modified.

III. NSPS Applicability

The Port Washington renovations are subject to the Act's NSPS if they constitute "modifications" within the meaning of section 111 and 40 CFR Part 60. Under 60.1, the NSPS applies to modifications at an "affected facility." Each unit at Port Washington is properly characterized as an "affected facility" subject to the NSPS at 40 CFR Part 60, Subpart Da, which applies to electric utility steam generating units [see 60.40(a)]. Pursuant to 60.14(a), a modification for NSPS purposes is defined as "any physical or operational change to an existing facility which results in an increase in the emission rate to the atmosphere of any pollutant to which a standard applies." Increase in emission rate is in turn defined as an increase in kilograms per hour (kg/hr) [see 60.14(b)].

Pursuant to longstanding EPA interpretations, the emission rate before and after a physical or operational change is evaluated at each unit by comparing the hourly potential emissions under current maximum capacity to emissions at maximum capacity after the change. In addition, under the Act's NSPS provisions, only physical limitations on maximum capacity are considered in determining potential emissions at power plants. Thus, any prospective changes in fuel or raw materials accompanying the physical or operational change are not considered in determining maximum capacity. Consequently, 60.14(b)(2) requires that, in conducting emissions tests before and after a change to determine whether an increase in emission rate has occurred, "operational parameters" which may affect emissions must be held constant. Fuel and raw materials are "operational parameters" for this purpose. Similarly, 60.14(e)(4) provides that use of an alternative fuel or raw material which the existing facility was designed to accommodate before the change would not be considered a modification. Thus, for example, a physical change which increases the maximum capacity of the facility would have a corresponding increase in the sulfur dioxide emissions if the facility used fuel with the same sulfur content before and after the change. Such a prospective increase cannot be offset by instead using fuel with a lower sulfur content after the change, because, under the regulations, the facility would always have the option of changing back to the higher sulfur-content fuel at a later date without triggering a modification for NSPS purposes. However, any offsetting reductions in emission rate caused by the concurrent addition of pollution control equipment would be considered in determining whether a physical or operational change results in an increase in emission rate.

The WEPCO contends (July 29, 1988 letter, at pages 20-27) that baseline capacity for the purpose of determining whether an increase in emission rate occurs for purposes of an NSPS modification is the original design capacity of the facility. This is incorrect. The thrust of the NSPS modification provisions is to compare actual maximum capacity before and after the change in question. Thus, original design capacity is irrelevant. The provision in 40 CFR 60.14(b)(2) for manual emission tests to determine whether an increase has occurred clearly contemplates that tests will be done just prior to and after the physical or operational change. The original design capacity of a unit, to the extent it differs from actual maximum capacity at the time of the test due to physical deterioration--and, hence, derating--of the facility, is immaterial to this calculation.

A. Physical or Operational Change

As with the Act's PSD provisions, a modification occurs for NSPS purposes, if there is either a physical or operational change [see 40 CFR 60.14(a)].

1. Physical Change

As is the case under the PSD provisions, the proposed renovations at Port Washington would constitute a physical change for NSPS purposes, at least at units 2, 3, 4, and 5. The WEPCO would need to supply more information, if EPA is to make a definitive determination as to unit 1.

The rear steam drums are part of the steam generating unit which constitutes the "affected facility" within the meaning of 40 CFR 60.41(a), and the drum replacements at units 2, 3, 4, and 5 are integral to the planned increase in maximum capacity, which is the purpose of the life extension project. With respect to unit 1, other physical changes would increase maximum capacity from 45 to 80 megawatts. However, there is some question whether those changes, in significant part, would occur at the steam generating unit or will be limited to the turbine/generator set, which is not part of the affected facility. We suggest that you pursue this matter with WEPCO to the extent necessary to determine NSPS applicability regarding unit 1.

As with PSD, the NSPS regulations exclude routine maintenance, repair, and replacement [see 60.14(e)(2)]. However, the renovations at the Port Washington steam generating units are not routine for NSPS purposes for the same reasons--detailed above--that they are not routine for PSD purposes.

2. Operational Change

Operational changes include both increases in hours of operation and increases in production rate. Section 60.14(e)(3) provides that an increase in hours of operation is not, by itself, a modification. However, an increase in production rate at an existing facility constitutes a modification, unless it can be accomplished without a capital expenditure on that facility [see 60.14(e)(2)].

It is highly likely that the life extension project at Port Washington constitutes an operational change under this standard, for two reasons. First, restoring nameplate capacity at units 1, 2, 3, and 4 presumably entails, among other things, changes that will allow the units to combust a larger amount of fuel at maximum capacity through operation at higher working pressures than the units have been able to accommodate in recent years. In the case of unit 5, the renovations presumably involve an increase over zero fuel and pressure. These changes constitute an increase in production rate within the meaning of the regulations. Second, as noted above in the discussion of PSD applicability, this increase in production rate entails substantial investments to improve the capital stock at each affected facility. It appears that these investments are large enough to qualify as "capital expenditures" under the formula specified in 60.2, although WEPCO should be asked to supply actual calculations should this become necessary to determine NSPS applicability.

B. Increase in Emission Rate

It seems clear that, absent some creditable offsetting changes, the increases in maximum generating capacity proposed for each of the Port Washington units would represent an increase in the hourly potential emission rate for each pollutant to which a standard applies over the emission rate prior to the renovation. As noted above, burning cleaner fuels would not be creditable. Similarly, voluntarily restricting the production rate following the renovations also would not be creditable for NSPS purposes, because WEPCO could, at a later date, increase production without triggering NSPS [see 40 CFR 60.14(e)(2)]. Accordingly, to avoid triggering NSPS, WEPCO would need to install additional air pollution control equipment, or upgrade existing equipment, to offset the potential emissions increases, such that no increase would occur at maximum capacity. The information submitted indicates that WEPCO may plan some enhancement of the current control equipment, but it is unclear whether this would be adequate to prevent an increase in emission rates. As with PSD applicability, such steps can lawfully avoid NSPS requirements. Accordingly, you should advise the company that it should address these contingencies if it desires EPA to rule on whether WEPCO can avoid NSPS requirements in this fashion.

C. Reconstruction

Based upon data provided by WEPCO, it seems that the Port Washington renovations would not qualify as a "reconstruction" for NSPS purposes under 40 CFR 60.15, because the capital cost for the upgrades to each of the five units, while substantial, apparently is less than 50 percent of the fixed capital cost of constructing a comparable, entirely new steam generating unit [see 60.15(b)(1)]. However, the modification and reconstruction provisions of NSPS are independent. The former provisions are intended to apply in circumstances where physical or operational changes which increase emissions make NSPS coverage appropriate at levels well below 50 percent of the capital cost of a replacement unit. Conversely, the reconstruction provisions are aimed at changes to an existing unit irrespective of associated emissions increases, but trigger NSPS requirements only if the higher 50 percent level is reached. Thus, the suggestion made by WEPCO in its July 29, 1988 letter (at pages 14-15) that EPA must undertake rulemaking to amend the reconstruction regulations before NSPS could be applied to the Port Washington project is not well taken.

IV. Conclusion

In adopting the PSD and NSPS programs, Congress sought to focus air pollution control efforts at an efficient and logical point: the making of long-term decisions regarding the creation or renewal of major stationary sources. The Port Washington life extension project, as it has been presented to EPA, would involve a substantial financial investment at pollution-emitting facilities that may significantly increase potential emissions of air pollutants over a period well beyond the current life expectancy of those facilities. If the additional factual information called for in this memorandum shows that emissions increases would indeed result from this project, the project would be subject to PSD and NSPS requirements. Such a result would be in harmony with the broad policy objectives that Congress intended to achieve through these programs.

cc: Gerald Emison, OAQPS
Alan Eckert, OGC

EXHIBIT D

October 14, 1988 Letter
from Lee M. Thomas to John W. Boston

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
WASHINGTON, D.C 20460

OCT 14 1988

THE ADMINISTRATOR

Mr. John W. Boston
Vice President
Wisconsin Electric Power Company
Post Office Box 2046
Milwaukee, Wisconsin 52301

Dear Mr. Boston:

As you requested in our meeting on September 15, 1988, I have made final determinations regarding the applicability of the Clean Air Act's New Source Performance Standards (NSPS) and Prevention of Significant Deterioration (PSD) requirements to the proposed life extension project at the Port Washington steam electric generating station, which is owned and operated by Wisconsin Electric Power Company (WEPCO). For the reasons discussed below, I have determined that, as proposed, the renovations at Port Washington are subject to both PSD and NSPS requirements. However, EPA remains willing to work with you regarding methods of compliance. As we have discussed, one alternative would be to reconfigure the project such that no emissions increases would occur. My staff is ready to meet with you to discuss these matters at any time.

I. BACKGROUND

On September 12, 1988, David Kee, Director, Air and Radiation Division, EPA Region V, wrote you regarding PSD and NSPS coverage of the Port Washington renovations. Enclosed with that letter was a memorandum dated September 9, 1988 from Don R. Clay, Acting Assistant Administrator, addressing the background of the Port Washington project, and analyzing at some length the relevant interpretative issues. For purposes of brevity, I will not repeat that material here, but rather incorporate it by reference.

The September documents concluded that the life extension project, as proposed, likely would be subject to PSD and NSPS requirements. However, EPA also stated that final applicability determinations could not be provided at that time in the absence of certain factual information. In our subsequent meeting you requested that EPA furnish final determinations, and agreed to provide the necessary additional information. You also asked EPA to reconsider certain of the conclusions in Don Clay's memorandum. These matters are discussed below.

II. FINAL DETERMINATIONS

Your staff has responded to our requests for additional information, and I want to thank you for WEPCO's continued cooperation in doing so. Based on this, and the other information in EPA's files, I now make the following final determinations:

(1) The life extension project, as proposed, will render WEPCO's Port Washington plant subject to the PSD requirements of Part C of the Clean Air Act as a major modification within the meaning of the Act and the EPA regulations at 40 C.F.R. § 52.21.

(2) The proposed life extension project will render each of the five steam generating units at the Port Washington plant subject to the NSPS requirements of section 111 of the Clean Air Act as a modification within the meaning of the Act and the EPA regulations at 40 C.F.R. Part 60.

In reconsidering the memorandum and letter of September 9 and 12, I have taken a careful look at the issues you raised in our meeting: whether the renovations are routine; whether EPA has treated similar projects in a different fashion; and whether there would be an emissions increase due to a physical or operational change. However, I find no reason to depart from the reasoning of the September documents. Accordingly, I conclude that WEPCO's life extension project, if carried out as proposed, will involve a substantial and non-routine renewal of the Port Washington facilities that will significantly increase both hourly maximum and annual emissions of air pollutants.

Specifically, regarding the nature of the proposed work at Port Washington, I find that these renovations constitute physical changes for PSD purposes within the meaning of 40 C.F.R. § 52.21(b)(2)(i), and physical and operational changes for NSPS purposes within the meaning of 40 C.F.R. § 60.14(a). I find further that these changes do not come within the PSD and NSPS exclusions for routine maintenance, repair, and replacement, nor the exclusions for increases in production rate or hours of operation. (See 40 C.F.R. §§ 52.21(b)(2)(iii) and 60.14(e)).

Regarding the emissions changes from the life extension project, based upon the emissions data and certain factual assertions submitted by WEPCO, I find that the Port Washington renovations will result in a significant net increase in emissions of several pollutants for PSD purposes within the meaning of 40 C.F.R. § 52.21(b)(2)(i), (b)(3), and (b)(21). I find further that the renovations will result in an increase in the emission rate of several pollutants at each of units 1-5 for NSPS purposes within the meaning of 40 C.F.R. § 60.14(a) and (b).

Enclosures A and B detail the emissions changes underlying these findings for PSD and NSPS purposes. As indicated above, EPA's calculations and determinations are based on data supplied by WEPCO. We will use the data in Enclosures A and B in the event you would like to work with us to establish an acceptable arrangement for satisfying PSD and NSPS requirements through the addition or enhancement of pollution control equipment, physical capacity restrictions, or, in the case of PSD, federally enforceable limitations on potential emissions.

III. <u>DISCUSSION</u>

As you requested, I have reconsidered the question of whether the physical and operational changes at Port Washington are routine, whether applying PSD and NSPS here would be inequitable in light of EPA's past treatment of renovation projects, and whether the renovations will result in emissions increases. These matters are addressed below, as is EPA's reasoning with respect to the baselines for calculating the PSD and NSPS emissions increases reflected in Enclosures A and B.

Regarding the question of routineness, the renovations involve the replacement of steam drums, air heaters, and other major components that are integral to the continued operation of the source. The work will not simply maintain the facilities in their current state, but rather will significantly enhance their present efficiency and capacity, and substantially extend their useful economic life. In addition, the work called for here is rarely, if ever, performed. Moreover, this work is costly, both in relative and absolute terms. Based on these and other factors, I reaffirm Don Clay's findings on the non-routine character of the Port Washington changes. The September 9 memorandum contains a complete discussion of EPA's reasoning on this issue.

On the related equity question, I find no inconsistency here with EPA's prior determinations regarding routine and non-routine changes. I note initially that PSD and NSPS applicability determinations are made on a case-by-case basis. Thus, it is very difficult to analogize to other projects, which almost inevitably present significant factual differences. Nevertheless, my staff has reviewed the additional material you submitted on September 19, and September 27, 1988 regarding certain other renovation projects, and has informally surveyed EPA Regional Offices and state agencies.

I have concluded that none of the four steam drum replacements identified in your September 19 submission are sufficiently similar to the Port Washington project to support determinations of nonapplicability in this matter. The Carolina

Power and Light case involved a faulty steam drum replaced prior to the initial start-up of a new unit, and would not have increased emissions for PSD or NSPS purposes. The Great Western Sugar example did not involve a utility boiler, and was too small to be affected by NSPS. The Ashland Oil facility was not at a utility, involved a waste heat boiler that was not fossil-fuel fired, and hence, was not an emissions unit subject to PSD or NSPS. The Algoma Steel Co. facility was not a utility boiler, and not located in the United States.

In addition, the informal survey conducted by the Office of Air and Radiation disclosed no closely analogous cases that were ever reviewed by EPA headquarters for purposes of PSD or NSPS applicability. In particular, EPA found no examples of steam drum replacement at aged electric generating facilities. Moreover, EPA could find no examples in which the Agency had analyzed and issued an applicability determination for a "life extension project" for any category of major source. Regarding the four utility projects identified in your September 27 submission, I note that they do not involve steam drum replacement. In addition, permit applications were not submitted to the state agencies for the Duke Power and Texas Utilities projects you cite. Consequently, they were not reviewed by any air pollution control agency. The Cincinnati Gas and Electric project was reviewed by the state, but not EPA. The state determined, and EPA Region II concurred, that the Hydraco Enterprises project was not subject to PSD based on a net decrease in emissions of all pollutants. Our informal survey and review of the projects you identified reveal that major construction activities undertaken by utilities that may be subject to Clean Air Act requirements have not been brought to the attention of EPA. The Agency is considering what steps may be necessary to address this situation.

EPA has discovered only two state agency determinations addressing life extension questions in a manner possibly inconsistent with EPA's analysis of the Port Washington project. These instances, which apparently were not brought to EPA's attention prior to the states' determination, do not create an inequity that would justify a different conclusion by EPA in this case.

As to the question of emissions increases at Port Washington, I believe that EPA has properly interpreted the PSD and NSPS regulations as applying to increases in emissions due to increases in hours of operation or production rate, where, as here, such operational or production increases are closely related to physical or operational changes. A contrary interpretation would allow even massive emissions increases stemming from significant new capital investment -- as distinguished from routine fluctuations in the business cycle --

to escape scrutiny under the Clean Air Act simply because the new investment did not involve an inherently more polluting production process. I do not believe that Congress intended such a result.

I would like to point out that the figures on emissions increases in Enclosures A and B reflect my conclusions regarding the proper points in time from which to calculate emissions changes. For PSD, I have determined under 40 C.F.R. § 52.21(b)(21)(ii) that the two-year period of 1983 and 1984 -- prior to the source curtailments due to discovery of cracks in the rear steam drums -- are more representative of normal source operations than the most recent two-year period. This conclusion is appropriate in light of WEPCO's historical operations.

As to NSPS, there is no "representative emissions" concept under that program. Rather, under the circumstances presented by this case, the baseline emission rates for units 1-5 are determined by hourly maximum capacity just prior to the renovations. At this time, EPA is relying on the actual operating data you submitted to determine current maximum capacity. Although EPA is certainly open to further discussion on this point, the information contained in your September 27 and October 11, 1988 submissions is inadequate to support WEPCO's assertions that higher-than-actual capacities could be achieved on an economically sustainable basis. For example, you indicate that operation at higher levels at units 1-4 "could increase equipment deterioration thus causing further damage." Regarding Unit 5, you state that "safety concerns" dictated the decision to shut down that unit. Based on this information, we are unable to rely on WEPCO's statements as to maximum "achievable" capacity in determining the emissions changes at each of these units. Thus, for example, in the case of unit 5, the current capacity must be regarded as zero.

IV. CONCLUSION

In adopting the PSD and NSPS programs, Congress intended to address the type of long-term capital investments in pollution-emitting facilities at issue in the Port Washington life extension project. Thus, as proposed, these renovations would be subject to the requirements of both programs. However, as indicated above, my staff remains ready to work closely with WEPCO to discuss specific pollution control equipment and permitting measures that would minimize the cost to WEPCO of complying with the requirements of the Clean Air Act. I have asked Don Clay to work with you in seeking a final resolution of the compliance issues by December 1.

Again, thank you for your cooperation in this matter.

Sincerely,

Lee M. Thomas

Enclosures

cc: Senator Robert W. Kasten, Jr.
Representative F. James Sensenbrenner, Jr.
Don Clay, EPA (ANR-445)
David Kee, Air & Radiation Div., Region V

Enclosure A

PSD Applicability

Port Washington Power Plant Renovation Project

(all emissions calculations are in tons per year)

Pollutant	Actual Emissions Baseline (1)	Potential Emissions (2)	Net Emissions Increase	PSD Level	Subje to PS Revie
Total suspended particulate	170	283 (3)	108	25	yes
Sulfur dioxide	24,236	52,621 (3)	28,385	40	yes
Nitrogen oxides	2,991	8,201	5,210	40	yes
Carbon monoxide	144	397	253	100	yes
Hydrocarbon	17	47	30	40	no
Beryllium	0.0016	0.005	0.0034	0.0004	ye
Fluorides	38	98	60	3	yes

NOTE: PSD applicability for the other PSD regulated pollutants listed at 40 CFR Section 52.21 (b)(23)(i) and (ii) has not been determined at this time.

1) Average emissions for two-year period defined by calendar years 1983 and 1984.

2) As calculated by WEPCO based on 1992 coal type, actual emissions after ESP, and an annual capacity utilization factor of 90%.

3) An EPA estimate of potential emissions, based on existing federally enforceable limits (i.e., applicable SIP), may be higher. The indicated PSD applicability determination would, however, not change.

Enclosure B

NSPS Applicability
Port Washington Power Plant Renovation Project

FULL LOAD EMISSIONS AT CURRENT CAPACITY (BEFORE RENOVATION)

	UNIT-1	UNIT-2	UNIT-3	UNIT-4	UNIT-5
SO2 (LBS/HR)	1417	1828	2043	1580	-0-
PM (LBS/HR)	15	16	12	12	-0-
NOx (LBS/HR)	480	352	289	221	-0-

FULL LOAD EMISSIONS AT FUTURE CAPACITY (AFTER RENOVATION)

	UNIT-1	UNIT-2	UNIT-3	UNIT-4	UNIT-5
SO2 (LBS/HR)	2046	2037	2088	2269	2695
PM (LBS/HR)	16	16	12	17	15
NOx (LBS/HR)	696	392	297	316	369

SUBJECT TO NSPS (AFTER RENOVATION)

	UNIT-1	UNIT-2	UNIT-3	UNIT-4	UNIT-5
SO2 (LBS/HR)	YES(a)	YES(a)	YES(a)	YES(a)	YES
PM (LBS/HR)	YES(b)	NO	NO	YES(b)	YES
NOx (LBS/HR)	YES(c)	YES(c)	YES(c)	YES(c)	YES(c)

Notes:

(a) With less add-on control than NSPS requirement, emissions (lb/hr) would not increase and NSPS would not apply.

(b) Because of planned ESP upgrade, PM emissions (lb/MM Btu) after renovation are expected to be less than NSPS requirement. However, NSPS would require CEMS for opacity.

(c) Because arch-fired boilers are used at Port Washington, current NOx emissions (lb/MM Btu) are expected to be less than NSPS requirements. However, NSPS would require a CEMS for NOx.

COMMENTS ON PINEY POINT PHOSPHATE'S PROPOSED REPAIR LIST
BY R.C. "BILL" BERRY 758-4713
FEBRUARY 14, 1997

SUMMARY

I have reviewed the list attached to Mr. Ivan Nance's letter dated December 17, 1996 to Mr. W. C. Thomas and feel that this list, together with statements contained in Mr. Nance's letter and the attached certification by Mr. Gerald W. Hartman, do not truly represent a repair effort but are, in fact, major modifications to the plant and may be alterations to the basic process under the guise of "repairs".

In my mind, repairs consist of replacing items that have broken or worn out with identical or very similar items. Repairs do not constitute changes in size, capacity or configuration. Several of the "repair" items on the repair and replacement list represent major changes in one or more of these categories.

Mr. Hartman's choice of words and punctuation in his certification could lead the reader to accept that there are no major changes but upon careful reading, it is apparent that the work to be performed might actually be a major process change.

Mr. Hartman applies the word "same" to capacity, design and emission limitations but after "design" includes in parentheses the words "double contact wet process".

The problem with this wording is that the plant was not designed to be, and is not now, a wet process sulfuric acid plant. It is, by definition, a "dry" process plant.

I am attaching a copy of a technical article titled "Alternatives in Sulfuric Acid Plant Design" that was published in Chemical Engineering Progress magazine in March of 1977 which discusses the various processes. On the first page, I have underlined a basic definition of the two processes.

Historically, wet process acid plants have used either smelter gases or oil refinery spent acids and sludges for feedstock and the line of demarcation between dry and wet plants was clear. It is my understanding, however, that Monsanto is now offering a sulfur burning process that does not strictly fit the criteria that the combustion air is dried immediately upon being drawn from the atmosphere and remains free of water throughout the rest of the process.

It is also my understanding that this new Monsanto process is the basis for the application to build a totally new plant.

In the absence of a material flow diagram, it is not possible to tell if that is what is being contemplated in the proposed "repairs". As part of the review and approval process, a material flow diagram should be requested to be included as part of the submittal.

If an objection is raised that this information is proprietary, a simple diagram, without flow rates, showing the sequence in which the various gas and acid streams flow through the plant should be requested. This would show whether a major process change is involved.

Further reinforcing the suspicion that major process changes may be involved are the statements regarding changing the sizes, types and metallurgy of major pieces of equipment and ductwork.

These changes would indicate that the basic heat and material balance of the plant is being altered and that the changes are required as a result of different flows, temperatures and gas compositions.

These changes will be discussed in detail in the comments on each proposed change which will follow this summary.

If the proposed changes do, in fact, constitute a change from the original process upon which the emission limits were approved, it will be up to others to decide whether the changes are sufficient to require permit review and modifications.

I am attaching a material flow diagram from a plant that was built in North Carolina and which was one of my projects while I was Senior Project Manager with Monsanto Enviro-Chem Systems. This flow diagram is essentially the same as the flow diagram for the original Piney Point plant. The only appreciable difference between this plant and the existing Piney Point plant should be a second converter, and associated heat exchange equipment, which was added by a previous operator.

I am also attaching a technical article titled "Design Options For Sulfuric Acid Plants" written by Jack Rinckhoff and Lenny Friedman, both of whom are well recognized as experts in the field of sulfuric acid plants. This article gives an excellent overview of options and variations in sulfuric acid plant design and may assist in understanding and evaluating my comments regarding the list submitted by Piney Point Phosphates.

I first worked with Jack Rinckhoff in 1958 when he was with Chemical Construction Company which, at that time, was a major competitor of Monsanto in sulfuric acid plant design and construction.

Lenny Friedman was Senior Process Engineer on several of my projects while I was Senior Project Manager with Davy-McKee Corporation, the company which succeeded Davy Powergas.

My comments on the individual items detailed in Exhibit 1 to Mr. Nance's letter are as follow and are in the same order as presented:

1. Sulfur Burner: No comment.

2. Boiler Feedwater Heater: No comment.

3. Waste Heat Boilers: No comment.

4. Economizer: Unless gas flows or temperatures have increased, why is a larger economizer required?

5. Main Compressor: No comment.

6. No. 1 Converter: Replacement of the 1st pass section with "high temperature" materials raises several questions. The operating temperature, and temperature rise, of the gas through the 1st pass of a converter are determined by the catalyst characteristics and, to my knowledge, haven't changed since the use of Vanadium Pentoxide catalyst began. The original plant was designed for those conditions and the materials selected were appropriate for the conditions.

   Have the temperatures changed?

   Are they using a different catalyst?

   Could it be that "high temperature" is also another term for corrosion resistant and that they are changing to 304 stainless steel which is "high temperature" but which would also be one of the choices for a wet gas plant?

7. No. 2 Converter: No comment except that this converter was not included when the plant was originally built and was added by a previous operator to increase production from the original design capacity of 1500 TPD to the current 2000TPD.

8. Acid Towers: The design of these towers needs to be reviewed since the efficiency of the towers, particularly the final tower, can have a major effect with regard to emissions. A reduction in size would indicate either reduced gas volume or a major increase in gas/acid contact efficiency.

Relocation of two of the towers to new foundations is a major change. Why is this being done? Reference is made to safety considerations in Mr. Nance's letter. Are these towers part of the safety relocation and why are they unsafe in their present location?

9. Mist Eliminators: My only comment here is that the eliminators should be defined and should be Brinks HE or equivalent eliminators in the final tower.

10. Heat Exchangers: The reduction in size of a heat exchanger in a plant that is being "repaired" indicates that the heat and material balance of the plant is being altered since only a change in duty should allow reduction in size. There is no indication that the exchangers, as originally installed, were oversized.

11. Superheater: No comment.

12. Condensate System: The change in metallurgy may or may not indicate a process change since condensate is inherently corrosive under certain conditions and this change may only reflect a safety factor against future corrosion problems.

13. Cooling Tower: This item also reflects a change in equipment sizing and could be related to either a change in the heat balance of the plant or to the different type of acid coolers being proposed since the proposed coolers have a better heat transfer coefficient.

14. Acid Coolers: The coolers originally installed in the plant were cast iron

AX sections (see Rinckhoff/Friedman page 80) which are not very efficient. The proposed shell and tube coolers, which are assumed to be of stainless steel construction, are much more efficient but do create a concern regarding corrosion rates in the final product acid storage tanks.

I am attaching an article discussing corrosion in acid storage tanks and, at the bottom of page 66, have underlined a portion of a paragraph discussing this. I will have further comments on this subject in my review of item 16 on the list.

In any case, the inclusion of these totally different type coolers does not constitute a "repair".

15. Acid Pump Tanks: The consolidation of the acid pump tanks is certainly a process change in that it alters the entire acid circulating system from what is known as a dual acid system to what is known as a mono acid system. On pages 79 and 80 of the article by Rinckhoff/Friedman, the difference in these systems, and the effect on the heat balance of the plant, is discussed.

16. Acid Storage Tanks: The repair of these tanks in a proper manner is crucial. There is a special consideration in inspecting acid storage tanks that have been out of service for extended lengths of time and this was not recognized by the operators of the plant at the time of the major acid spill in 1989 that caused the evacuation of 400 people. I will address this in other comments that will follow the items on this list.

17. Plant Stack/ Water System: No comment.

18. Pumps: No comment.

19. Ducts: Four new ducts to relocated towers are not repair items and we again find a change in metallurgy that is unexplained but could be related to a change in gas composition.

20. Misc. Pipe/Valves: No comment.

21. SO2 Monitor: No comment.

22. Office: No comment.

23. Civil, Structural Insulation, Electrical, Painting: New piling and foundations for the new acid towers in their relocated positions are not repair items.

Reference to a new MCC to be located adjacent to the existing MCC would imply that new equipment, in addition to that now in use, will be installed. Again, this is not a repair item.

24. Instrumentation: While complete replacement of the pneumatic instrumentation system with an electronic system does not constitute a repair, it is one of the few items listed where replacement rather than repair makes sense and is justified.

OTHER COMMENTS

In addition to the comments on the individual items on the Piney Point Phosphate list, there are several items that are either an expansion of previous comments or are items that I feel should be addressed before the plant is allowed to be started up by any operator. These comments are as follow:

ACID STORAGE TANKS

I have previously indicated that the proper inspection of these tanks is crucial and particularly so in light of the 1989 spill.

The attached article on storage tanks discusses the problems with inlet location, iron content, storage temperature and other factors.

What was not discussed directly is what caused the 1989 failure.

In addition to the previously discussed considerations, there is a condition that can cause severe corrosion in tanks that sit in an empty condition. In empty tanks, the natural changes in air temperature and barometric pressure cause the tank to "breathe".

This causes moisture in the air to come in contact with residual acid that cannot be totally drained from the tank and in contact with the tank walls where condensate runs down and creates a very corrosive weak acid.

Since the center of the bottom of the tank is higher than the perimeter, this acid collects at the juncture of the sidewall and the bottom plate. As enough weak acid accumulates, it flows to the outlet elbow in the bottom of the tank where it sits and corrodes the elbow. This elbow is in a notch or box in the foundation of the tank and the back side of the elbow is under the tank where it cannot be inspected or checked for thickness.

The back, or long radius, side of the elbow is also subjected to the highest velocity when acid is being withdrawn from the tank and is, therefore, subject to scouring action that removes any passive film that otherwise might accumulate.

The elbow connects to the outlet shutoff valve of the tank and is, therefore, between the tank and the valve. The shutoff valve is useless if the elbow fails and this is what happened when the major acid spill occurred.

It is my understanding that the elbow was replaced after the spill but it is unknown how many times since the spill the tank has been sitting empty and subject to the same conditions that caused the failure.

As part of the "repairs", this elbow, and any others similarly located, should be replaced.

In addition, the tanks should be checked for thickness by ultra-sound testing and the critical welds in the tank shell should, in addition, be checked by X-ray for hydrogen or other inclusions. The X-ray examination should include, as a minimum, the intersections of vertical and horizontal welds in the tank shells and the weld connections between the tank shells and bottom plates.

Checking of the thickness of the tank shells will allow calculation of the hoop stress present when the tanks are in operation and will determine their suitability for continued operation.

ACID CIRCULATING SYSTEM

The other major environmental problem at the plant occurred when the Northern part of Manatee County was covered with SO3 gas causing respiratory problems for many people.

I was told by a man who was an employee at the plant when the problem occurred that the plant operator failed to turn on the acid circulating pump on the final absorbing tower. This allowed raw SO3 gas to be discharged directly to the atmosphere. This problem can occur when acid circulation is lost or reduced for any reason.

One solution to this problem would be to meter the flow going into the tower and interlock the meter to shut the plant down whenever acid flow fell below a predetermined level. The problem with this solution is that the large size of the piping would require that the meters for sulfuric acid service would be extremely expensive. Piney Point Phosphates would probably strongly oppose these meters on the premise that the meters could also fail and that the cost cannot be justified.

One other measure of acid flow is the amount of current going to the circulating pump motors. This current provides another means of preventing plant operation unless the proper amount of acid is being delivered to the absorbing towers.

Installation of undercurrent relays, with time delays, in the motor control equipment for the pumps would allow shutting down the main blower and sulfur pumps in the event of low acid flow whether this was caused by operator error, a broken pump shaft, worn or plugged impellers, closed pump discharge valves or any other reason. I will be happy to discuss this with you in more detail since it represents a relatively inexpensive means of providing insurance at a cost that should not be objectionable to a responsible operator.

EMISSIONS

When the capacity of a sulfuric acid plant is stated, this figure does not really mean too much unless it is related to the strength of the SO2 gas leaving the sulfur furnace.

Because of this, a plant operator has the opportunity to, within certain limits, control the emissions from the plant to be whatever is necessary to satisfy testing requirements depending on how the limits are specified and how production is measured. There is latitude for the operator to "play games" with the emissions and those attempting to measure them.

The concept is not complicated but the explanation, and variables, can be lengthy and are best stated verbally. I will be happy to discuss this in detail.

AMMONIA SYSTEM

While a great amount of attention is being given to the sulfuric acid plant and the possibility of environmental and health problems associated with this plant, there is also a much more lethal system in the complex that presents a very real danger of catastrophic failure. This is the ammonia system that supplies the fertilizer plant in the complex. Ammonia gas, even in relatively low concentrations, can cause death and certainly severe respiratory problems.

To the best of my knowledge, the ammonia is still being stored in the original horizontal cylindrical pressurized storage tanks commonly referred to as "bullets". These tanks can reach a pressure of around 300 psig on a hot day and it is quite common to spray the exteriors of these tanks with water to hold the pressure down and prevent the relief valves from blowing off.

Installed integral to the outlets are excess flow valves that are designed to close if excess flow should take place for any reason, such as a broken ammonia pipe. The location of these valves, which are partly inside the tank, prevents inspection of the closing mechanism and, historically, the only way to test them for proper operation has been to return them periodically to the manufacturer for testing.

Further complicating this is the fact that fertilizer grade ammonia contains a small amount of water that can cause corrosion of the valves and their closing mechanisms, particularly when the tanks are not in regular operation. In addition, the water can also, over a period of time, corrode the interior of the tanks. This could be a particular possibility if the tanks have been left empty and open to the atmosphere where they could "breathe" high humidity ambient air either through tank openings or open ammonia pipes and valves.

Considering that there have been several plant operators and years of inactivity, there is the real possibility that these tanks have been neglected and could be in poor condition.

It is very important that these excess flow valves are tested prior to resumption of plant operation, or replaced with new valves, and that the tank shells are checked for corrosion and proper thickness.

GENERAL

It is important to note that my comments are not intended to imply that there is anything wrong with any new process that Piney Point Phosphates and Monsanto Enviro-Chem Systems may be intending to employ. My only objection is that there may be evidence that they are trying to introduce a new process under the guise of "repairs" and circumvent the appropriate approval processes.

My opinion is that the Piney Point Plant, in the hands of responsible operators and properly renovated and maintained, can be an asset to Manatee County. It can provide jobs and revenue, through taxes, that can be beneficial.

I feel, however, that considering the history of this plant, it is vital to all concerned that any efforts to put the plant in operation must be made with honesty and the full knowledge of all concerned and without even a hint of subterfuge. More than economic and political considerations are concerned with this issue. Lives are at stake.

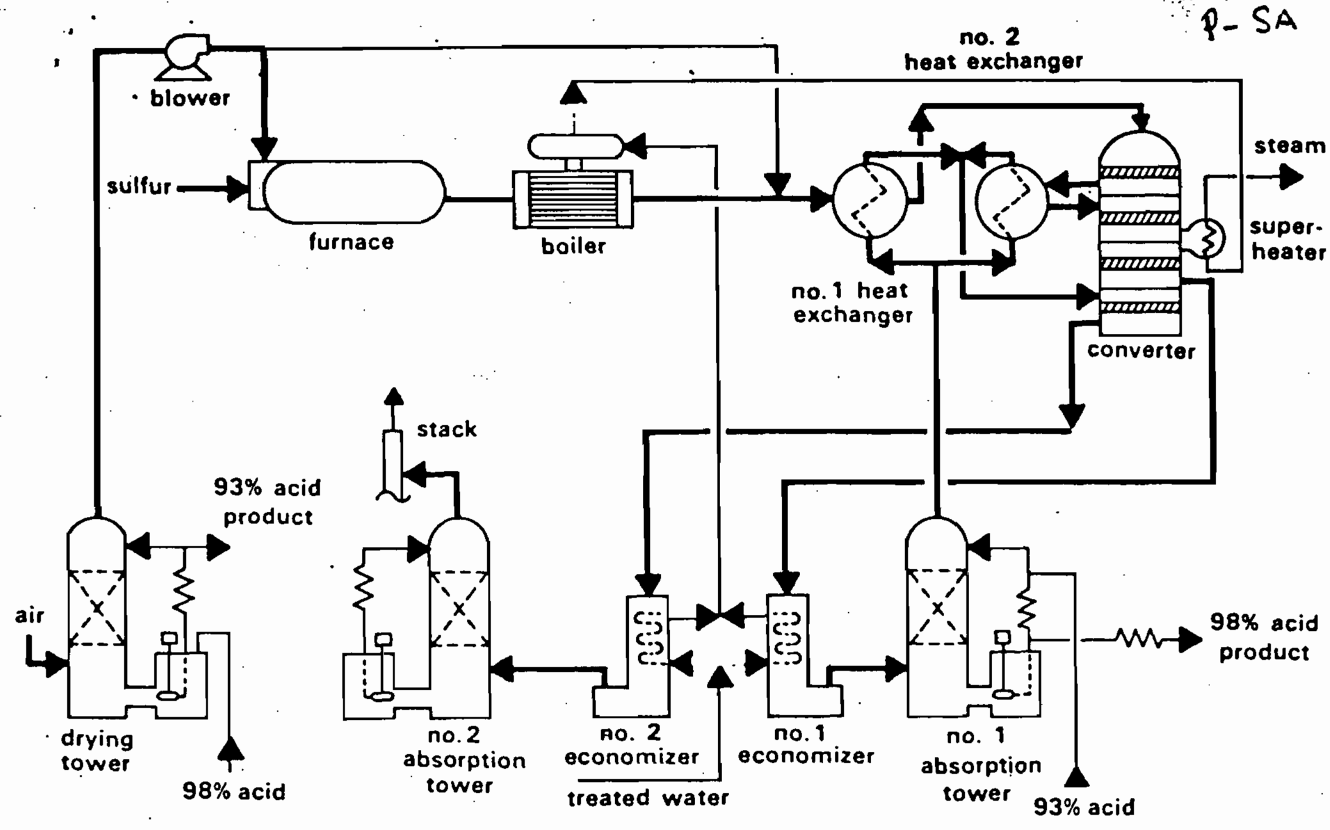


Figure 1. Typical sulfur burning DC/DA sulfuric acid plant.

Sulfuric Acid Plant Operations:

Alternatives in Sulfuric Acid Plant Design

A 1,000 ton/day DC/DA plant costs about $770,000 more to build than a SC/SA facility of equal capacity, but outputs nearly $540,000 worth of additional acid each year from the same amounts of sulfur and air.

R. W. Riedel, J. J. Knight, and R. E. Warner
The Ralph M. Parsons Co., Pasadena, Calif.

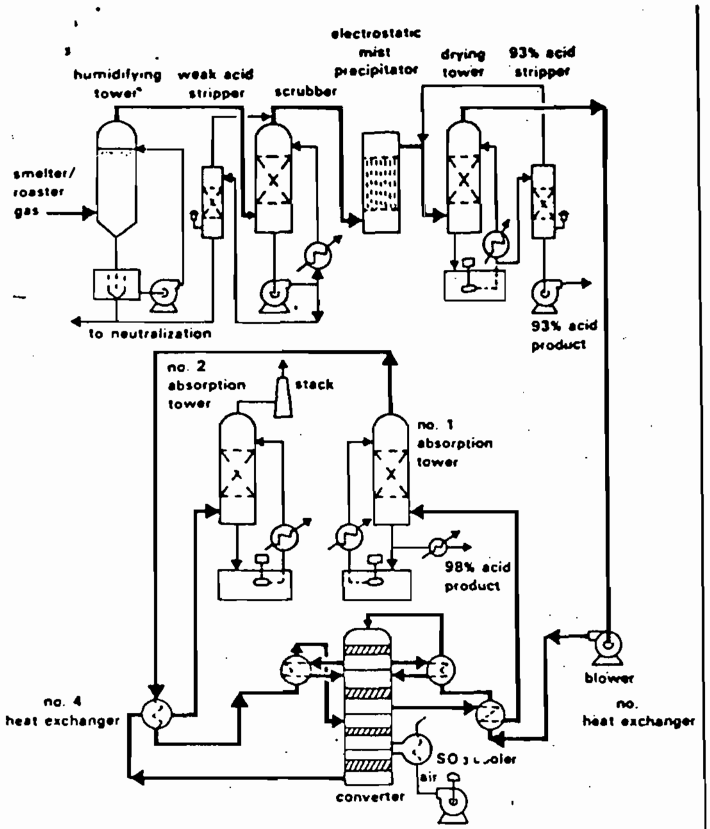
When the design of a new sulfuric acid plant is being developed, or when substantial revisions are being considered to an existing facility, rich rewards can be realized if careful consideration is given to certain areas of plant design that have, until recently, often been accorded little attention.

Basically, there are two kinds of sulfuric acid plants; those that use the dry gas (sulfur burning) process, and those that use the wet gas process. The former, Figure 1, is so named because the air is dried immediately upon being drawn from the atmosphere and remains free of water throughout the rest of the process.

In the wet gas process, Figure 2, the SO_2 gas stream entering the plant brings with it a large amount of water vapor. This gas is usually hot (500 to 800°F) and dusty, and may also contain impurities such as fluorides that could seriously harm the catalyst in the contact section of the plant. It is, therefore, cooled and purified in a series of scrubbers and electrostatic precipitators and finally dried before entering the contact section of the plant. The purified gas (before the drying tower) is saturated with water vapor.

The SO_2 gas streams feeding such plants come from a variety of sources, including: metallurgical smelters (copper, zinc, lead, etc.), pyrite roasters, waste acid decomposition furnaces, and hydrogen sulfide burners.

The double contact/double absorption (DC/DA) process differs from the single contact/single absorption (SC/SA) process principally in that it has an intermediate SO_3 absorption tower added ahead of the final conversion stage. Estimates of the additional cost for building a new sulfur burning DC/DA plant range from "approximately



▲Figure 2. Typical smelter/roaster gas wet process DC/DA sulfuric acid plant.

the same investment" (*1*) up to 13% more (*2*) than for a SC/SA plant. It seems unrealistic to expect to get an extra absorber, mist eliminator, acid cooler, and related piping and ducting at no cost. Therefore, consider 10% as a reasonable estimate for the added fixed capital requirement for a DC/DA plant. Then, if a 1,000 ton/day DC/DA battery limits plant were to cost $8.5 million, its SC/SA counterpart would cost $7.73 million, or a difference of $770,000.

Advantages of DC/DA

However, comparing a DC/DA plant operating at 99.7% conversion efficiency to a SC/SA plant at 97%, both producing 1,000 ton/day of acid (100% basis), 350 days/yr., the sulfur consumed in the DC/DA plant will be nearly 3,200 tons, or $175,000 less per year than in the SC/SA plant, if sulfur is valued at $55/ton. Expressed another way, if both plants were fed exactly the same amount of sulfur and air, and if the product acid had a value of $55/ton, the DC/DA plant would produce nearly $540,000 worth of additional acid in a year than the SC/SA plant.

Some schemes have been developed for multiple (more than two) contact/multiple absorption sulfuric acid plants. If the hypothetical 1,000-ton/day DC/DA plant were extended to become a TC/TA (T = triple) plant at an added cost of, say, $650,000, and achieved a conversion of 99.96%, it would "save" only about $16,000/yr. in sulfur or "add" $50,000/yr. in saleable acid production.

To evaluate comparative operating costs, however, one must recognize that a DC/DA plant will consume more energy and produce less "bonus heat steam" (a more appropriate term than "waste heat steam") for export than its SC/SA brother. This is partly because the gas return-

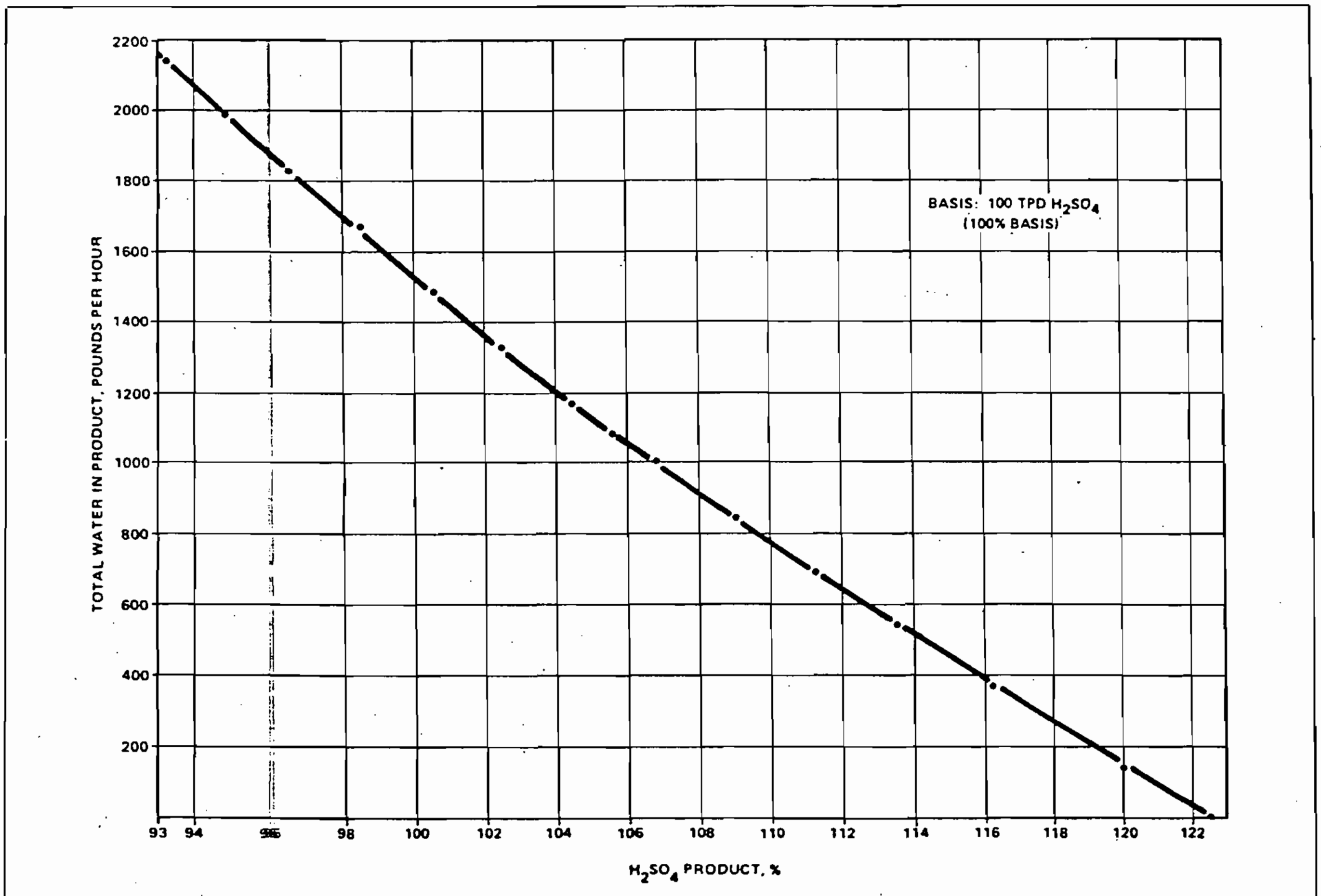


Figure 3. Total water present in product acid vs. product concentration.

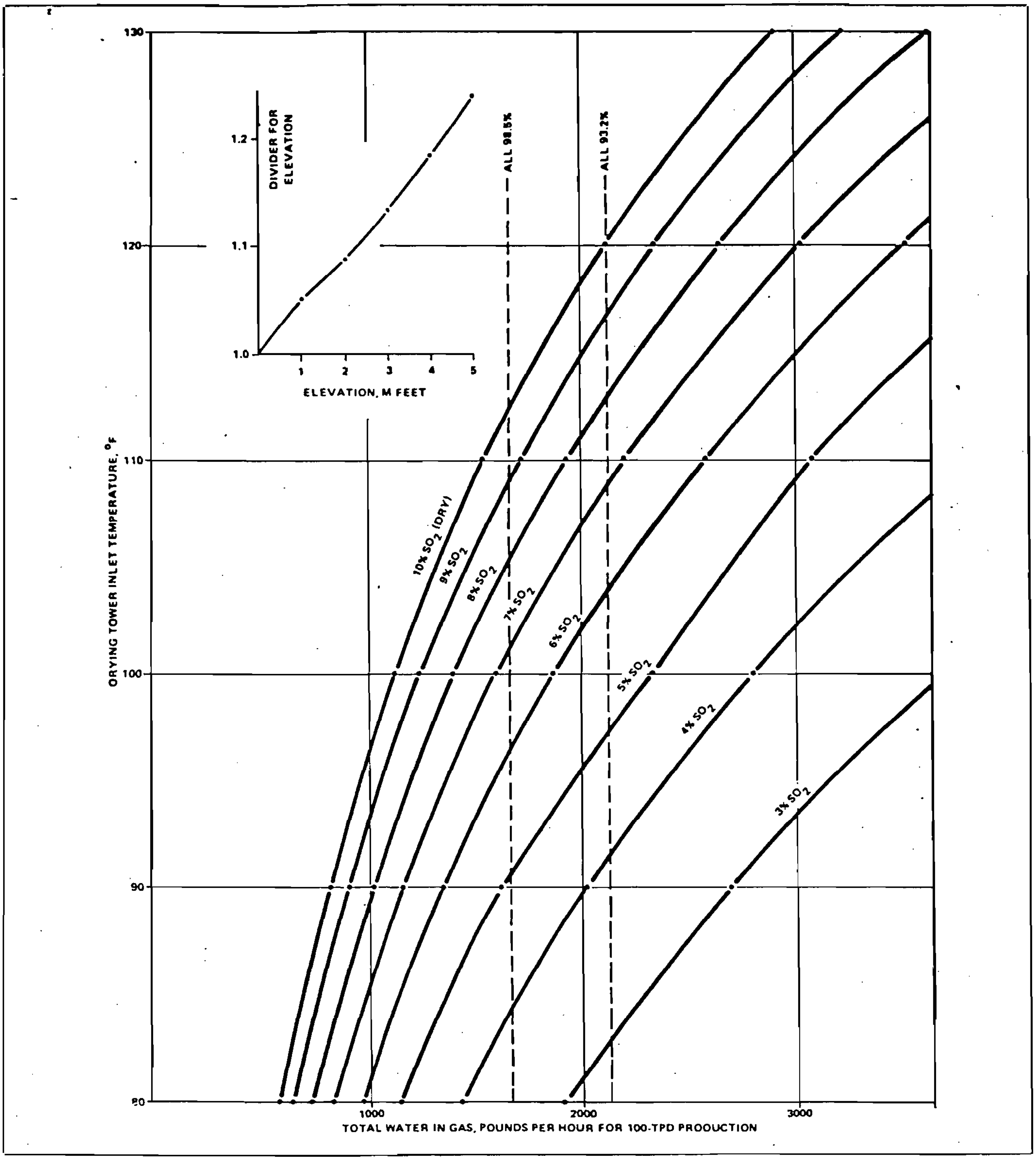


Figure 4. Water vapor content in process gas vs. temperature at drying tower inlet.

ing from the intermediate absorber must be reheated to conversion temperature before undergoing the final stage of conversion. Only a portion of this heat (along with the heat of added conversion) is recovered in the steam system. The net difference will be about 12 million B.t.u./hr. in a 1,000 ton/day sulfur burning plant with an overall SO_2 of 10.2%. Then, too, the blower will require extra power to overcome the greater pressure drop. More cooling water circulation will be needed, and the acid circulation pump will need to be operated for the added absorption tower. Together, these will typically add the equivalent of 1.7 million B.t.u./hr. to the power demand. This, added to the 12 million B.t.u./hr. of unrecovered steam, equals 13.7 million B.t.u./hr. in reduced steam production.

Assume that this heat would otherwise have been used at some point in the complex. Therefore, it must be made up for by, for example, burning fuel in a power house. With fuel oil at $12.60/bbl. and 6.1 million B.t.u./bbl., the annual fuel oil cost will be around $240,000. Deducting the $175,000 annual raw material saving shows that direct

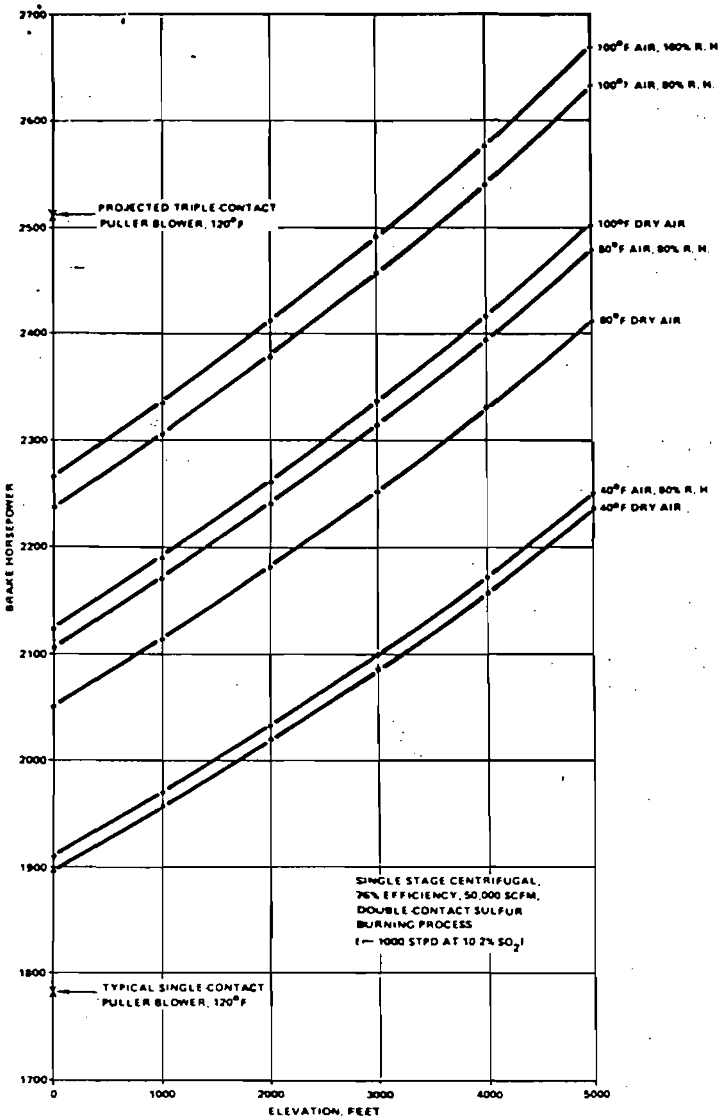


Figure 5. Brake h.p. requirements for pusher blowers.

unit operating cost for a DC/DA plant is only about 19¢/ton more than for an SC/SA plant. If your accounting philosophy permits you to reflect instead the extra \$540,000 worth of product that will be produced from the same amount of raw material, you may actually be able to find an 86¢/ton *advantage* in direct unit operating cost for DC/DA. Repeating this exercise for a hypothetical TC/TA plant produces very discouraging numbers that will not be reported here.

Another disadvantage of triple contact is that the burning of liquid fuel (in compliance with EPA limits) to make up for the heat loss would in itself dump into the atmosphere fully 10% of the amount of SO_2 that the triple contact feature might hypothetically recover.

If, on the other hand, you belong to that endangered species who still dumps (or plans to dump) your excess bonus heat steam to the atmosphere, you may simply languish in the raw material savings and ignore the reduced thermal efficiency.

Much the same philosophy can be applied to pyrite burning and waste acid regenerating plants because both usually generate steam. The "value" of the various raw materials used in wet gas plants varies too widely from location to location to make any generalized comparison of DC/DA vs. SC/SA economics.

In any case, the effect on investment of applying double contact technology to wet gas plants is, on a percentage basis, not as great as in dry gas plants. Since the cost of the purification section may typically be in the range of 40% of the cost for the entire plant and is unaffected by the type of contact process used, a 10% increase in the cost of the contact system would add only 6% to the cost of the whole plant.

The foregoing may seem somewhat academic, considering that current U.S. environmental regulations will apparently require that all future acid plants employ DC/DA, or some more advanced technology, for compliance. However, it may help to assuage the feelings of your management when they learn that their new acid plant is going to cost five or 10% more than the SC/SA plant that would have served their purpose several years ago disregarding inflation.

Water balance in wet gas plants

Following a wet gas purification system, the gas entering the drying tower will be saturated with water vapor. All this water will be taken up in the drying tower acid and will eventually appear in the product acid either as part of the sulfuric acid molecule or as the aqueous portion of the sulfuric acid solution.

The stronger the desired product strength, the cooler the gas must be made in the purification system. Cooling the gas costs money, both in heat exchange surface and in cooling water requirements. Of course, the water vapor that is not condensed in the purification system will be condensed in the drying tower, and the overall heat load will be the same. However, the LMTD on the drying acid cooler is usually much better than that on the purification liquor cooler. The additional heat can, therefore, be taken up in the drying acid cooler with a smaller increase in its size than would be required in the liquor cooler.

The multiplicity of types of heat exchangers and materials as well as the virtually infinite combinations of operating conditions make it necessary to evaluate each case as it arises, but optimization in this area should produce savings in investment and operating costs.

Figures 3 and 4 enable the convenient determination of the temperature to which a gas must be cooled to produce the desired acid, as illustrated in the following example:

Let us assume that gas strength (to the converter) is 7% SO_2, that the product (100% basis) is 200 ton/day as 98.5% plus 200 ton/day as 93.2%, and that the elevation is 2,000 ft.

By referring to Figure 3; 100 ton/day of 98.5% acid represents 1,670 lb./hr. H_2O, and 2 × 1,670 = 3,340; and 100 ton/day of 93.2% acid represents 2,140 lb./hr. H_2O, and 2 × 2,140 = 4,280. Thus, total H_2O in product is 7,620 lb./hr.

Decide what portion of the water you wish to add to the drying and absorption tower systems as liquid water for the purpose of strength control. For this example, say 15%. Then, 7,620 − (0.15)(7,620) = 6,477 lb./hr. permitted in gas.

By referring to Figure 4, at 2,000 ft. elevation, the correction factor is about 1.09. Thus, 6,477 ÷ 1.09 = 5,942 lb./hr. And dividing by 4 (hundreds of tons/day) = 1,486 lb./hr. H_2O permitted in the gas. Figure 4 shows that a 7% SO_2 gas will have to be cooled to 98°F.

Autothermality

In wet gas plants, it is always necessary to preheat the gas to the catalytic ignition temperature before introducing it into the converter. Most of the required heat is usually supplied by the heat of conversion of SO_2 to SO_3 (41,350 B.t.u./lb. mole). In cases where the gas strength (vol. % SO_2) is reasonably high (say over 5.5%), the heat of conversion is sufficient to supply all of the heat required.

As the gas strengths decrease, however, the temperatures of the gases issuing from the various catalyst masses also decrease substantially. The resultant drop in the available LMTD in the gas-to-gas heat exchangers must be overcome by increasing their surface area. Eventually, the size required for the heat exchangers will exceed economic and/or practical feasibility. At this point, the process is no longer autothermal, and it becomes necessary to supply supplementary heat from some other source.

This heat is often supplied by burning fuel oil. A plant having a thermal deficiency of 10 million B.t.u./hr. will consume $220,000 of fuel annually in this manner (allowing 80% thermal efficiency). Alternatively, burning elemental sulfur in an in-line furnace will generate heat at near perfect efficiency and, of course, produce additional acid as well. In this case, the sulfur requirement would be about 23 ton/day. At $55/ton, this sulfur would cost over $440,000/yr., but it would produce acid that might sell on today's market for over $1.3 million.

Such a furnace can also be used to produce acid when the smelter (or other SO_2 source) is shut down, even if producing only enough acid to keep the plant hot and ready to receive smelter gas.

Blower location

The main process air blower may fit into the process either before or after the drying tower. When before, it is called a "pusher blower" because it pushes the air through the drying tower. When after, it is called a "puller blower" because it pulls the air through the tower.

A puller blower requires more horsepower than a pusher because of its higher ratio of absolute discharge pressure to absolute suction pressure, and because the drying tower is normally operating above ambient temperature. In very humid areas, however, this disadvantage may largely be made up because the pusher blower has the burden of compressing the water vapor in the air, while the puller does not. Figures 5 and 6 enable a rapid comparison of the horsepower requirements for both types of blowers at different elevations and operating conditions for dry gas plants.

(Virtually all wet gas plants use the puller blower approach for at least two good reasons: First, to protect the blower from the corrosiveness of the wet gas coming from the purification system and, second, to utilize the heat of compression to further assure the autothermality of such plants and, in some cases, to generate steam.)

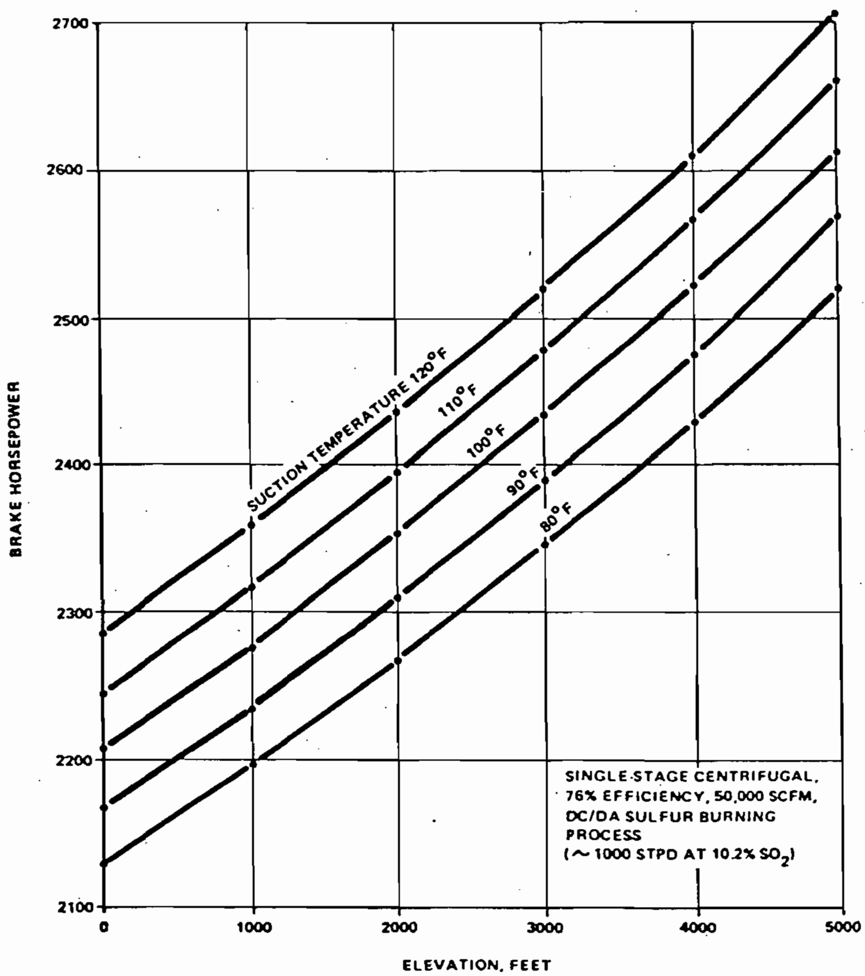
In dry gas plants of the pusher blower type, the heat of compression is absorbed in the drying acid, ultimately to be lost in the cooling water system. A puller blower delivers this heat into the process where it will be used in the production of steam.

Example: Item 1. A pusher blower at sea level delivering 50,000 std. cu. ft./min. (dry basis) air at 80°F (before compression) and 80% relative humidity into a drying tower. Air leaves the tower at 120°F. From Figure 5, the brake h.p. requirement is 2,106.

Item 2. A puller blower at sea level drawing the same amount of air at 120°F from the drying tower will have a discharge temperature of 225°F, as indicated in Figure 7, and it will draw 2,284 brake h.p. (from Figure 6). Equipment pressure drops are the same in both cases.

The difference in brake h.p. = 2,284 − 2,106 = 178 h.p.

Figure 6. Brake h.p. requirements for puller blowers.



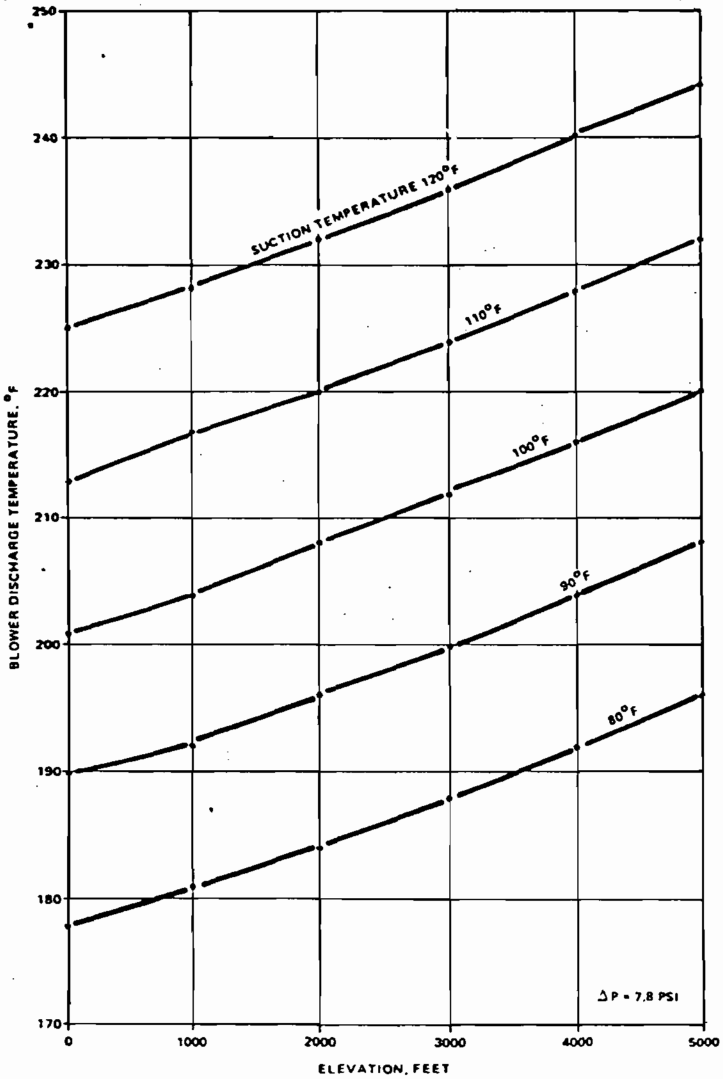


Figure 7. Puller blower discharge temperature at various elevations and suction temperatures.

since 1 h.p.-hr. = 2,545 B.t.u., then 178 h.p.-hr. = 453,000 B.t.u./hr.

The difference in the enthalpy of the air entering the furnace is determined as follows: 50,000 std. cu. ft./min. = 242,340 lb./hr. The temperature difference = 225 − 120 = 105°F, and specific heat = 0.25. Then, (242,340)(105)(0.25) = 6,361,000 B.t.u./hr. And, the net energy advantage for puller blower = 6,361,000 − 453,000 = 5.9 million B.t.u./hr.

One can substitute one's own dollar equivalents for energy costs, but at 2¢/kWh for electricity, this is nearly $300,000/yr. Note also that the duty on the drying acid cooler and the cooling water system is reduced by around 5.7 million B.t.u./hr. in this example.

In the past, many air blowers have been placed in the pusher position to protect the blower itself from acid mist carryover from the drying tower. Modern mist eliminating devices have substantially eliminated this problem.

Upgrading existing plants

Existing SC/SA plants can be upgraded to DC/DA performance levels in either of two ways:

1. Add-on facilities. This method basically collects the stack gas from an existing SC/SA plant, reheats it by burning fuel, passes it through an additional conversion stage, then absorbs the newly-formed SO_3 in a final absorption tower before emitting the gas to the atmosphere.

2. Revamping existing facilities. When sufficient process heat is reliably available (as in most dry gas plants and high SO_2 strength wet gas plants), and when existing equipment is of suitable design, it is often possible to convert an SC/SA plant into a DC/DA plant. The job requires addition of gas-to-gas heat exchangers, a new absorption tower, mist eliminator, acid cooler, and duct revisions. Some revisions may also be required on the blower and inside the converter.

Again, the plethora of existing plant designs and requirements makes it necessary to refrain from generalization and to consider each case in detail on its own merits. A number of forward-thinking producers have built SC/SA plants that have been specifically designed in every respect to allow for future upgrading to DC/DA with minimal cost and interruption to operations.

In conclusion

Scientists and engineers have responded admirably in supplying the technology needed to meet recent environmental and energy shortage challenges. Double contact technology will probably dominate the world sulfuric acid manufacturing scene for the near future. Multiple contact and other as yet undemonstrated technologies are available to be applied if and when needed. As with so many endeavors in our increasingly technological world, the manufacture of sulfuric acid is transforming from an art to a science. Those involved in this metamorphosis will perform accordingly or perish. #

Literature cited

1. Atmospheric Emissions from Sulfuric Acid Manufacturing Processes, U.S. Dept. of Health, Education, and Welfare, Cincinnati, Ohio (1965).
2. Kronseder, J. G., "Economics of High Conversion Sulfuric Acid Plants," AIChE 61st Annual Meeting, Los Angeles, Calif. (December, 1968).

R. W. Reidel, senior process engineer for The Ralph M. Parsons Co., has more than 17 years engineering and manufacturing experience in heavy basic and fine chemicals for industry and agriculture. He holds a B.S.Ch.E. from Grove City College.

J. K. Knight, senior project engineer for The Ralph M. Parsons Co., has more than 30 years experience in plant and project engineering in the chemical manufacturing industry. This includes extensive work in sulfur and sulfuric acid facilities. He holds a B.S. degree in mechanical engineering from the Univ. of Utah and is a registered mechanical engineer in California.

R. E. Warner, senior process engineer for The Ralph M. Parsons Co., has been responsible for the design of 23 operating sulfuric acid plants. His background includes process engineering and operation of petroleum refineries, sulfur recovery units, and sulfuric acid plants throughout the world. Warner earned his B.S.Ch.E. from Pennsylvania State Univ.

Sulfuric Acid Plant Operations:

Design Options For Sulfuric Acid Plants

Even though this is one of the oldest chemical processes in existence and one that is highly standardized, there are a number of options that can affect plant reliability, cost, emissions, etc.

J. B. Rinckhoff and L. J. Friedman, Davy Powergas, Inc., Lakeland, Fla.

Although there has been very little change in the process for making sulfuric acid since the successful development of the contact process just before the turn of this century, there have been many mechanical design changes and improvements.

The so-called double catalysis, or double absorption, process is not new. Its recent popularity is due to environmental rather than economic considerations, inasmuch as it requires a 10 to 15% increase in capital cost plus higher operating costs to provide only a 2% rise in overall efficiency.

Mechanical changes, on the other hand, have come about for a number of reasons. Some have resulted from availability of new materials; others were necessitated by the huge increase in capacity of single plants in the past 40 years, more than 20 to 1. Most of the improvements have been well publicized and accepted. Others are less well known, and "old wives' tales" still exist in the industry regarding the acceptability of some design features. It is hoped that this article will help to overcome that problem.

A sulfuric acid plant today need not be a standard "off-the-shelf" item that the buyer must accept. A wide variety of options is available that can affect plant reliability, flexibility, energy balance, capital cost, and emission control. This article compares the options available for the acid system, the steam system, the main blower, sulfur burning, emission control, carbon steel corrosion, instrumentation, and the start-up heater. The comparisons are based on conditions in a sulfur burning plant, but many are applicable to "wet gas" plants such as those operating with metallurgical gas, refinery spent acid, hydrogen sulfide, etc.

Acid system

Only one concentration of acid is a must for the operation of the plant. This is the nominal 98% acid that provides essentially complete absorption of the SO_3 produced. Other concentrations of acid may also be used in the plant, such as 93 to 96% for the drying tower and various strengths of oleum in a first absorber if that strength of product acid is required. An oleum tower is always followed by a 98% absorber to complete the absorption of SO_3 from the gas.

The several options to be considered in the design of the acid system are summarized below and reviewed in some detail in the following sections: strength and temperature of drying tower acid, use of mono or dual acid system, type and location of acid coolers, and product acid strengths and production rates.

Drying tower acid. A drying tower is provided at the inlet to the contact section of the acid plant to remove water vapor from the air or gas entering the plant. Satisfactory drying can be accomplished with 93% acid at 110°F, with 98% acid as hot as 170°F, or with intermediate strengths and temperatures such as 96% acid at 140°F. Acids of those strengths at the indicated temperatures have the same partial pressure of water vapor, and the temperatures indicated are the maximum recommended for that strength.

To maintain these concentrations, the diluted acid leaving the drying tower must be mixed with the stronger acid from the absorber. This can be accomplished for 93 to 96% drying acid by cross transfer of acid between the drying and absorbing systems. For 98% drying acid, infinite cross transfer would be required, which is accomplished by using a common pump tank for the dryer and absorber.

Table 1. Applicable heats for comparing effect of increasing steam production.

	Heat, million B.t.u./hr.		Increase
Dried Air, @ 110°F	2.0	—	
Dried Air, @ 160°F	—	5.1	+3.1
Blower, Before D.T.	0.0	—	
Blower, After D.T.	—	4.3	+4.3
Combustion of Sulfur	108.9	108.9	
Conversion to SO_3	35.9	35.9	
Loss to Interstage	−18.4	−18.4	
Loss to F.A.T. −450°F	−20.1	—	
Loss to F.A.T. 400°F	—	−17.4	+2.7
Total Heat to Steam	108.3	118.4	+10.1

This is referred to as a mono acid system with both the dryer and absorber operating with 98% acid.

The temperature of the air or gas leaving the drying tower is nearly the same as the temperature of the acid entering the tower. This temperature has an effect on several operating factors in the plant.

A higher acid inlet temperature will reduce the acid cooling duty because more heat is picked up by the air or gas stream.

In a sulfur burning plant, a higher acid inlet temperature will result in an increase in steam production because the air going to the furnace is hotter. An increase from 110° to 170°F in the temperature of the air going to the sulfur furnace will increase the total steam production in a double catalysis plant by about 3.5%.

Mono or dual acid system. If a product in the range of 93 to 96% is desired, it can be withdrawn from a drying tower system operated at the desired concentration, or 98% acid can be withdrawn from a mono acid system and diluted in a separate dilution system.

The temperature rise resulting from the dilution of 98% acid is high, and a recirculated system with a cooler is normally used to avoid excessive temperatures in the diluter. In the case of a dual acid system, this heat of dilution occurs in the drying tower system. The acid circulation rate is high, so the temperature rise is small.

The overall installed cost of a mono acid system is generally slightly less than that of a dual acid system. This is primarily due to the reduced acid cooler costs resulting from the higher temperature level in the acid drying system. The total reaction heat is the same in either case, and the only difference in the total acid heat duty is the result of the higher acid inlet temperature to the drying tower with the mono acid system.

There are relative merits and disadvantages in each of the systems. In the mono acid system, an extra circulating system is required for the diluter if a product acid strength less than 98% acid is required. A common pump tank is used for the drying and absorption tower in the mono acid system, eliminating the need for cross transfer between these acids. A mono acid drying tower can be operated hotter to permit greater steam production and to reduce the acid cooling duty.

Acid coolers. In the normal double catalysis sulfuric acid plant, the heat to be removed from the acid system is usually at least 80,000 B.t.u./hr./daily ton of acid production. The actual heat load depends on several factors, including product acid strength, humidity of gas entering drying tower, and whether a single or a double catalysis plant is used.

A number of different types of acid coolers are in use today. The plant location, with respect to availability and quality of cooling water as well as atmospheric temperature and humidity, will have an effect on the selection of the type of cooler.

The early acid plants in the 1930s and 40s generally used trombone-type coolers. These were banks of horizontal runs of cast iron pipe (usually 6 in. in diameter) with return bends mounted one above the other on posts, and with a water distribution trough on top. The heat transfer coefficient for these coolers is low compared to more modern designs, and the space required is excessive. They had the advantage that leaks could be patched with chemical putty and a pipe clamp, and that external scale could be easily chipped off.

The well-known AX sections currently offered by Pentex were introduced in the 1940s and soon became the standard in the acid industry. They are S-shaped cast iron sections with internal fins designed for stacking, with a water distribution pan on top of each stack. These provide a better heat transfer coefficient and more efficient water distribution, and they require much less plot area than the trombone coolers. Leaks cannot be easily patched, and usually a complete stack is replaced when a leak develops in one of the sections.

The certainty that any cast iron acid cooler will eventually have leaks led to the development and introduction in the early 1970s of acid coolers of stainless steel and Teflon. There have been some problems with these units, however, and some questions about their serviceability remain to be answered.

The stainless steel shell and tube units offered by Chemetics are furnished with anodic protection. Acid is cooled in the shell side by water flowing through the tubes. The units can be installed either horizontally or vertically and require very little plot area. Two shells in parallel may be required for absorber acid cooling in large plants, but normally only one shell is needed for each duty. A high chloride content in the cooling water may cause some problems. It will, at the least, require the use of a higher alloy and increase the cost of the cooler.

The Teflon tube bundle type of acid cooler offered by Du Pont is normally installed in an annular section of the pump tank. Cooling water flows through the tubes of several bundles in parallel while the acid flows through the annular section around several bundles in series. Some failures have occurred as a result of abrasion and excessive pressure. It appears that repetition of these can be avoided by added safety features and by careful operation.

In a comparison of installed capital costs, the trombone coolers are the most expensive and the other three are in the same general price range.

Product acid. Any strength of sulfuric acid can be produced in the plant. As indicated above, some concentrations, such as 93 to 96%, 98 to 99%, and 20 to 40% oleum, can be withdrawn directly from the appropriate circulating system. A separate dilution system is required for strengths below 93%, or below 98% if a mono acid system is used. Intermediate acid strengths may be produced by blending two product strengths. Higher strength oleums or liquid SO_3 can be produced if an oleum reboiler and additional equipment is provided.

The normal operating temperature of most acid streams in the plant is too high to be delivered to storage tanks, and product acid coolers are required. The only exception is 93% acid, which is normally cooled to about 110°F for use in the drying tower.

Steam system

When acid is produced from sulfur, considerable excess heat is generated that is usually used to produce steam.

This heat results from the combustion of sulfur to SO_2 and the further oxidation of SO_2 to SO_3. Most of this reaction heat is available for steam except for the usual small heat losses to the atmosphere and the larger loss in the gas going to the absorber. This loss is partially offset by the heat available in the air leaving the drying tower and by the heat of compression in the blower if this is after the drying tower. It should be noted that an improved heat recovery to steam usually results in a reduction in acid cooling duty.

There are several options to be considered in the design of the steam system of the plant: increasing steam production, steam pressure and temperature, and use of steam.

Increasing steam production. A good way to evaluate the effect of various design options is to start with a specific base case and determine the effect of various changes. A reasonable base case is a 1,000 short ton/day sulfur burning, double catalysis sulfuric acid plant, operating with a 9.5% SO_2 gas in a 2 + 2 converter system to obtain 99.7% conversion of SO_2 to SO_3.

Heat available to steam and superheat is expressed in million B.t.u./hr. Heat entering in the feed water is not included in this comparison. The available heat is equal to the heat in the dry air going to the sulfur furnace (including any bypass), plus the heat of combustion of sulfur and the heat of conversion of SO_2 to SO_3, less the heat loss to the acid in the interstage absorber and the total heat in the gas going to the final absorber.

There is about 4% heat loss from the overall system, but this is constant for all cases and is neglected. When burning dark sulfur, there is additional heat available from the combustion of the hydrocarbon contamination, which is also neglected in this comparison.

The basis for comparison is a 1,000 short ton/day plant with the blower before the drying tower and the dry air going to the sulfur furnace at 110°F. The gas going to the interstage absorber is cooled only by reheating the gas returning to the converter, and the gas going to the final absorber is cooled to 450°F in the economizer.

Table 1 shows the applicable heats for the suggested basis for comparison, in million B.t.u./hr. It also shows the increase in the total heat to steam with the following improvements: blower after drying tower (70°F temperature rise); mono acid with dry air 160°F; and gas to final absorber at 400°F.

Steam pressure and temperature. Steam can be generated at any practical pressure in the acid plant because the boiling temperature increases relatively little with pressure. Most of the recent plants have steam systems in the 450 to 600 lb./sq.in. gauge range.

The type of feed water treatment required may be the determining factor in the selection of the boiler operating pressure. A zeolite system may be adequate with the available water supply for a 450 lb./sq.in. gauge boiler with slightly high blowdown, while a demineralized system may be required for a 600 lb./sq.in. gauge boiler.

Some superheating of the steam is advisable to protect the steam turbine drives from wet steam. A higher degree of superheat may be preferred where a more efficient use of the steam is desired. Increasing the superheat temperature reduces the quantity of steam produced because the total heat available to steam is unchanged.

It is important to remember that the primary function of the acid plant is to produce acid as efficiently as possible. The steam producing facilities are included to remove excess heat and to maintain optimum operating temperatures in the plant.

Use of steam. In most sulfur burning sulfuric acid plants, the main blower and the normally operating feed water pump are steam turbine-driven. This does not require all of the steam produced, and in some plants one or more of the acid circulating and cooling water pumps are also operated with turbine drives.

In a few plants, an attempt has been made to make the plant completely self-sufficient on steam so that it can continue operation during a power outage. This normally requires that at least some of the turbines be operated condensing, thus reducing the quantity of low pressure steam available for offsite uses. It also, of course, requires a small generator to supply power for instruments, lighting, and small motors.

Consideration must be given to the requirement for stand-by steam for a cold plant start-up if many steam turbine drives are used. The main blower can be operated at reduced capacity with a lower steam flow and pressure, but acid pumps must be operated at full capacity to provide adequate circulation over the towers. Adequate steam supply can also be a problem when operating at reduced rate. Steam production is less but acid circulation, for instance, must be maintained at full rate.

Many sulfur burning sulfuric acid plants are part of a phosphate fertilizer complex in which there is a need for large quantities of low-pressure steam for use in the phosphoric acid evaporators. To meet this requirement, back pressure turbines are used to drive the main blower, and possibly other equipment, to provide 30 lb./sq.in. gauge steam at the acid plant battery limits. Excess high pressure steam may also be reduced to this level if a convenient use is not available.

A more efficient use of the energy available in the steam can be achieved by directing all the steam to a turbo-generator set and extracting the steam required for jets and evaporators at the appropriate pressure levels. In this case, it would be advantageous to generate the steam at a higher pressure and temperature level to improve the energy recovery.

Main blower

The main blower is normally a single stage centrifugal unit and is by far the largest energy consumer in the acid plant. It provides the power required to move the air or gas through the entire plant.

In the early sulfur burning contact plants built in the 1930s the design was very conservative, and the total pressure drop through a clean plant was only about 40 in. water column, or less than 1.5 lb./sq.in. These were small plants, on the order of 100 ton/day or less.

As plant capacities increased, so did the gas velocities and pressure drops in the plant. With present plant sizes on the order of 2,000 ton/day, and with the necessary additions for pollution control, the pressure drop through a clean plant is about 160 in. water or nearly 6 lb./sq.in. With a normal allowance of about 1 lb./sq.in. for pressure build-up in the plant, a 2,000 ton/day plant requires a 5,000 to 6,000 h.p. blower.

There are several blower options to be considered: blower location, blower pressure rise, and blower driver.

Blower location. In a sulfur burning plant, there are two possible choices of blower location: either before or after the drying tower. There are valid reasons, as well as outdated ones, that can affect the choice.

With a blower before the drying tower, air is handled at atmospheric temperature with the added weight of atmospheric humidity, and the ambient conditions are variable. A blower after the tower handles only dry air at a constant but higher temperature. It also handles a slightly higher pressure ratio because of the reduced inlet pressure.

A silencer is required if the blower is before the tower, but the tower serves as a silencer when the blower is after the tower.

With a 6 lb./sq.in. pressure rise across the blower, the air is heated about 90°F by the blower. With a blower before the drying tower, the acid cooling duty is increased by this heat. With a blower after the drying tower, this added heat goes to the furnace and boiler to produce more steam.

With a blower after the drying tower, there has been some concern about acid carry-over from the tower, which would result in sulfate accumulation on the blower impeller and casing. This did cause an occasional problem before the present mesh-type entrainment separators were available. However, the "wet gas" type of acid plants operating with smelter gas, spent acid, or H_2S have always operated with the blower after the drying tower and their operating records, even before entrainment separators, were good. With a suitable separator after the drying tower, carry-over to the blower is essentially eliminated.

Blower pressure rise. It was indicated earlier that the design basis pressure drop through a clean sulfur burning plant has increased from 40 to 160 in. over the past 40 years. There was good economic justification for increasing the gas velocities and the allowable pressure drop across boilers and exchangers to reduce the size and cost of the plant. With the present concern over the energy shortage, however, it may be time to reverse the trend toward higher pressure drop in acid plant design.

Another pressure consideration is the allowance for pressure build-up in the plant during the operating period between plant turnarounds. This allowance, which is normally specified as about 1 lb./sq.in., is intended to permit the plant to continue to operate at its rated capacity throughout the operating cycle. It is used by some operators, however, to operate considerably above design rates when the plant is clean. This can adversely affect the life of the plant by operating at temperatures well above design.

In a brand new plant, when all of the heat transfer surfaces in the acid and steam systems are sparkling clean, this overcapacity can probably be achieved while maintaining normal temperatures in the plant. This can be very misleading and it has, on occasion, provided a false impression of the future potential overcapacity of the plant.

It is generally impractical to specify much more than 1 lb./sq.in. dirt factor in blower pressure rise. In most cases, the major portion of the pressure increase in the plant occurs in the first catalyst bed. The catalyst is supported on castings, and it is impractical to select a material or a design for these castings that will withstand a pressure of 1 lb./sq.in. more than the clean plant resistance for an extended period without sagging.

In the normal sulfur burning plant design today, the pressure drop through the catalyst beds in the converter is about one fourth of the total pressure drop in a clean plant. This pressure drop through the catalyst could be cut in half by increasing the converter diameter by 15%. This not only reduces the gas velocity by 25%, but it also reduces the total depth of the catalyst beds by 25% since the total volume of catalyst required remains the same. The increase in pressure drop across the catalyst bed resulting from entrapment of foreign matter will also be reduced since the surface area of the bed in the above case will be increased by one third.

Blower driver. The main blowers in sulfur burning acid plants are usually operated with a turbine driver because steam is available in the plant. A turbine drive is convenient for throttling for operation at reduced rates. The pressure drop through the plant is essentially all friction loss, and it therefore varies as the square of the gas flow. With a turbine drive, the blower speed and the resulting gas pressure rise are reduced as the gas flow is decreased.

With a motor-driven blower, it is generally uneconomical to consider any sort of variable speed drive. The simplest way to reduce gas flow is to throttle at the inlet of the blower, generally with a butterfly damper.

With a constant speed driver, the pressure rise across the blower increases with reduced gas flow. This is the reverse of the plant requirement, and the excess pressure must be wasted across the throttling damper. For this reason, the constant speed motor drive becomes very inefficient at reduced operating rates.

The efficiency at reduced rate can be greatly improved by the use of adjustable inlet guide vanes for throttling. These are installed in the inlet of the blower. As they are closed, they impart a spin to the incoming gas in the direction of impeller rotation. This has an effect similar to reducing the impeller diameter, thus reducing the pressure rise across the blower and the required horsepower input.

Sulfur burning

Molten sulfur is very similar to a light fuel oil, and there should be no difficulty in achieving efficient combustion. It is probably for just this reason that sulfur burning is frequently given less consideration than it deserves. In an 1,800 ton/day sulfuric acid plant, the heat release in the sulfur furnace is just under 200 million B.t.u./hr., resulting from the combustion of 49,000 lb./hr. of sulfur. This requires a large furnace with well-designed burners.

There are two important considerations: furnace operating temperature, and sulfur burner design.

Furnace operating temperature. The sulfur furnace is normally operated at a temperature in the range of 1,700 to 2,000°F, depending on several factors. Burning sulfur in dry air to produce a gas containing 10% SO_2 will give a temperature rise of about 1,600°F. If the blower is ahead of the drying tower, the furnace temperature with a 10% SO_2 gas may be as low as 1,725°F if 93% acid at 100°F is delivered to the drying tower.

For the same gas strength, the furnace temperature will be higher if a higher drying acid temperature is used, as in the mono-acid system, or if the air is preheated by using it for cooling, or if the blower is after the drying tower.

The upper limit of 2,000°F is usually accepted as a safe temperature for entering the fire tube boiler following the furnace as long as the hot tube sheet is protected with castable refractory and ceramic ferrules.

This higher furnace temperature is generally achieved by bypassing a portion of the air around the furnace and boiler, resulting in a higher SO_2 concentration in the furnace gas. This higher furnace temperature with the cold air bypass has two major advantages. It reduces the size of the waste-heat boiler following the furnace by increasing the temperature differential at both ends of the boiler and by reducing the gas flow through the boiler. It also provides a flow of cold bypass air to reduce the operating temperature of the boiler hot gas bypass damper, which is used to control the temperature of the gas going to the converter. With no cold bypass, this damper must operate with gas at the furnace temperature.

Sulfur burner design. In the early acid plants, solid sulfur was charged to a rotary kiln where it melted and was burned from the walls of the kiln. Some unburned sulfur vapor was carried with the gas and burned in a subsequent combustion chamber after admission of additional air. The development of sulfur melting facilities led to the use of pressure atomizing spray burners in a number of different arrangements. The current design is usually a horizontal cylindrical furnace operating with a combustion air pressure of 5 to 6 lb./sq.in. gauge and with as many as five or six pressure atomizing sprays. The sprays normally operate at about 75 lb./sq.in. gauge. If the pressure is reduced much below this level, larger droplets are formed and some unburned sulfur may leave the furnace.

The latest improvement is the use of a spinning cup burner for atomizing the sulfur feed to the furnace. A single burner of this type can be used for plants producing up to 2,000 ton/day of acid. The burner gives excellent atomization with an almost infinite turndown ratio, and because of the better atomization it can be operated in a much smaller furnace than the pressure atomized burners for the same capacity.

Emission control

The EPA has established limits on gaseous emission levels for all new sulfuric acid plants, divided into two categories. For acid plants operating with non-ferrous metallurgical gases, the limit is 650 parts/million SO_2 because of the variable nature of the feed gas streams. For plants producing acid by burning elemental sulfur, alkylation acid, hydrogen sulfide, organic sulfides, and mercaptans or acid sludge, the limits are 4 lb. of SO_2 and 0.15 lb. of H_2SO_4 mist/ton of acid produced.

These SO_2 levels are lower than can be achieved in single absorption acid plants, but there are two ways of meeting the limits: double absorption, and ammonia scrubbing. Various types of mist eliminators are available to protect the plant and reduce the acid mist emission.

Double absorption. This is the generally accepted approach for a new sulfuric acid plant that must obtain at least 99.7% conversion efficiency to maintain an SO_2 emission of not more than 4 lb. of SO_2/ton of H_2SO_4 produced. These plants usually have four stages of conversion, but some five-stage plants have been built.

There are two schools of thought with respect to the location of the interstage absorber in the flow scheme.

One holds that if it is located after the second stage of conversion, the temperature of the gas leaving the converter is high enough to provide a good temperature differential so that this gas can be used to reheat the gas returning to the converter. This minimizes duct runs and avoids interference with other bed temperatures if adjustments are required.

This 2 + 2 scheme leaves two conversion stages after the interstage absorber. With adequate cooling provided between these stages, a low temperature can always be maintained at the exit of the last bed to insure good final conversion even with aging catalyst or upset conditions in the first two beds.

Others maintain that if the gas passes through three stages of conversion before going to the interstage absorber, more of the SO_2 will be converted to SO_3 and be removed from the system. This should permit a slightly higher overall conversion for the 3 + 1 scheme if the temperature of the gas leaving the final stage is low enough. Aging of the catalyst or any upsets in the first three stages will, however, increase the quantity of SO_2 reaching the fourth stage, resulting in a greater temperature rise and, therefore, a higher exit temperature for this stage.

As insurance against this, a fifth stage can be added to make a 3 + 2 converter. The increased cost for an additional catalyst bed support and another heat exchanger makes the insurance expensive with only a slight increase in efficiency.

Ammonia scrubbing. The largest single consumer of sulfuric acid is the phosphate fertilizer industry, which also uses large quantities of ammonia. If the fertilizer plant can regularly use a relatively small quantity of a strong ammonium sulfate solution in its operations, there is a very definite advantage to using a single absorption sulfuric acid plant followed by an ammonia scrubber to reduce the SO_2 in the stack gas to an acceptable level. The installed cost for this system is less than that for a double absorption plant.

If the ammonia value can be recovered in the fertilizer operation, the operating cost of the acid plant with an ammonia scrubber is less than that of a double absorption plant. The ammonia scrubber provides a simple, dependable operation that can maintain a low SO_2 emission from the acid plant consistently, including start-up and upset conditions.

The ammonium sulfite/bisulfite solution produced is acidulated with sulfuric acid. Liberated SO_2 is returned to the acid plant, and the ammonium sulfate produced is available as a concentrated solution which can be evaporated to a dry solid if necessary. The sulfuric acid required for acidulation is less than the equivalent of the recovered SO_2.

Mist elimination. For most new sulfuric acid plants, the EPA has set a limit of 0.15 lb. of acid mist in the stack gas per ton of H_2SO_4 produced. In sulfur burning plants operating with 10% SO_2 in the gas going to the converter, this quantity of acid mist is equal to about 1 mg. of H_2SO_4/std.cu.ft. of stack gas. The mist loading in the gas leaving the absorber is generally more than this, and some form of mist eliminator is required to meet the EPA standard.

Electrostatic mist precipitators in carbon steel have been used for this service in a few instances, but the results have not been too successful. These units have a low pressure drop but a high capital cost.

The generally accepted units today fall into two categories with regard to particle size of the mist removed. The York S and the Brink HV units are both expected to remove essentially all particles 3 μ and larger, but with the efficiency falling off very rapidly with smaller particles. Both units are designed for a pressure drop of about 10 in. water column.

Either of the units will usually provide satisfactory removal of acid mist under normal operating conditions. During start-up or upset conditions, there may be some visible plume. Some plant operating conditions, such as a gas stream containing NO_x or the production of high-strength oleum, promote the production of submicron particles and a higher efficiency demister is required.

These are the so-called candle type elements such as the Brink HE or the Cebeco units. They are cylindrical, generally 24 in. diameter, with glass fiber packing between two concentric stainless steel screen supports. The elements are mounted either above or below a tube sheet and are usually 10 ft. or more in length. They can be installed either in an extension on top of the absorber or in a separate vessel after the absorber. The collection efficiency of these units is not dependent on gas velocity, so the pressure drop is controlled by the number of elements installed. Economics usually justify a pressure drop of about 10 in. water column.

Corrosion of carbon steel

Carbon steel is generally suitable for handling the dry SO_2 and SO_3 gases in the contact section of sulfuric acid plants. Scaling of the steel at elevated temperatures in some areas of the plant does not cause serious loss of metal. The problem is with fouling of heat exchanger surfaces and the catalyst beds. A properly applied aluminum coating can prevent scale formation and the resulting problems. Application of the coating is expensive, and there is a question as to how much of it can be justified.

The problem in the converter is the scale falling on the layer of quartz pebbles above the catalyst beds. This, of course, increases the pressure drop through the beds, which eventually reduces the plant capacity. A more critical effect results from the fact that the scale accumulation is not uniformly distributed so that part of the catalyst bed is blinded, and the remainder of the catalyst on the bed is overloaded and does not provide maximum conversion.

The scaling can be avoided by metallizing the surfaces with aluminum, usually during fabrication of the vessel. It consists of sandblasting to white metal, followed immediately by flame spraying of aluminum to 10 mil. thickness. This is an expensive operation, and a decision must be made as to how much of the interior surface should be metallized.

Heat exchangers are affected by scaling in two ways. Scale on the tubes acts as insulation and reduces the heat transfer rate. Scale also roughens surfaces and blocks gas flow passages to increase the pressure drop across the exchangers.

The amount of scaling that takes place is related to the operating temperature. With gas temperatures below 900°F, scaling of carbon steel is generally not serious. With higher temperatures, some precautions should be taken. Low chrome-moly tubes have been used, but in some plants, these have shown evidence of scaling. More recently, Alonized tubes have been used successfully.

Acid attack of gas-to-gas exchangers is always the result of bad operation elsewhere in the plant, which should be corrected at its source. In sulfur burning plants, corrosion on the tube side is the result of excessive moisture in the gas, usually from a leak in a boiler or in the steam jacketed sulfur piping. Similar corrosion may also occur during plant heat-up with direct firing. Water from combustion of hydrocarbons combines with SO_3 retained in the catalyst, and the resulting acid condenses in the cooler portions further on in the plant.

Corrosion on the shell side of the exchanger by acid in the gas returning from the interstage absorber was a serious problem in the early double absorption plants. Lurgi solved it by a simple method that is practically fool-proof; by preventing condensation of sulfuric acid vapor from the gas. Gas leaving the interstage absorber is saturated with sulfuric acid vapor at essentially the temperature of the acid entering the tower (6 to 8 mg. H_2SO_4/std. cu. ft.). If the duct wall is cooler than the gas, some of this acid vapor will condense. Lurgi overcame this problem by jacketing this duct and passing some of the hot gas going from the converter to the absorber through the jacket.

Others have tried steam tracing this duct with disastrous results in some cases. Apparently, some areas were left cold so that acid condensed and then very seriously attacked the duct in the heated areas.

Instrumentation

There is frequently a question as to the degree of instrumentation desired or required in a sulfuric acid plant. There is the glamor of data logging and computer control vs. the practicality of a simpler installation.

A very limited number of instruments is required to provide essential information for control of acid plant operation. These include furnace and converter temperatures, acid strengths, and boiler levels. Other instruments are helpful in monitoring the operation, such as ammeters, pressure gauges, and additional temperature points. There are still other data, such as pressure drops, that should be logged regularly so that long-term trends can be spotted or to help in troubleshooting if the unexpected upset occurs.

Pollution control agencies require measurements of production rate, stack gas flow, and SO_2 emission. The plant accountants may want measurements of utility consumptions and product and byproduct deliveries.

Remote manual operators for dampers and throttle valves permit the operator to stay in the control room, but they also probably limit his inspection trips through the plant.

Automatic control can easily be applied to most operations in the plant, but it may reduce the operators' interest in the operation and limit his ability to take over in case of instrument failure.

A sulfur burning acid plant is usually a very steady operation once it is lined out at the desired capacity. Full automatic controls would be very hard to justify, but certain safety features are a necessity. These include sulfur feed shut-off for low-low boiler water level and low blower air pressure and alarms for such items as pump failure, high furnace temperature, or low and high boiler water level. Automatic control of acid strength and pump tank levels is fairly easy to justify because it may help to avoid a messy spill or a bad stack.

In a plant operating with metallurgical gas, the concentration of SO_2 in the gas entering the converter is not constant. This is especially true of gas from copper converters. The variations in SO_2 content affect the converter temperatures and the instantaneous acid production rate. In these plants, automatic control of converter temperatures as well as acid strength and pump tank levels may be necessary to assure compliance with emission regulations.

Start-up heater

The use of an indirectly fired start-up heater will prolong the life of the catalyst and of the plant. If the heating is by direct firing, the gas contains moisture from combustion of the hydrocarbon fuel. This moisture will combine with any SO_3 remaining in the plant, especially in the catalyst. The resulting acid then condenses in the cooler portions of the plant, where it corrodes the cast iron and steel and softens the catalyst, voiding the manufacturer's guarantee.

The damage caused by direct firing can be kept to a minimum by suitable purging of the plant before shutdown to eliminate SO_3 from the converter. The purging is most effective if the catalyst is kept hot, and it may be necessary to fuel fire in the sulfur furnace after the sulfur is shut off to keep the temperature high enough for effective purging.

The use of an indirectly fired start-up heater reduces the time required for reheating a plant from dead cold. A longer heating time is required with direct firing since at least two or three "dry blows" are necessary to heat the catalyst sufficiently to minimize acid formation and condensation on the catalyst even after good purging on shutdown.

J. B. Rinckhoff, who earned his B.S. degree from Lafayette College, is principal engineer, sulfuric acid, for Davy Powergas, Inc. Prior to 1970, he held a similar position with Chemico in its New York office.

L. J. Friedman, a supervising engineer specializing in sulfuric acid and sulfur processes for Davy Powergas, Inc., earned his B.S.Ch.E. from Polytechnic Institute of Brooklyn. He has done graduate work in nuclear engineering at SUNY at Buffalo and in business administration at Pace College Graduate School.

Sulfuric Acid Plant Operations:

Corrosion In Sulfuric Acid Storage Tanks

API 650, a code that was originally drawn up for the design of oil storage tanks, also serves as the standard for constructing tanks that hold sulfuric acid. There is considerable evidence to show that it should be amended.

D. Fyfe, R. Vanderland, and J. Rodda, Chemetics International, Ltd., Willowdale, Ontario, Canada

Storage tanks for sulfuric acid have traditionally been regarded as relatively unimportant adjuncts to the plants that produce or use the acid. In the main, they are infrequently inspected, and when a problem does develop the tanks are often repaired in the absence of corrective action to prevent recurrence of the difficulty.

Despite such treatment, however, these tanks have been providing what has been regarded as acceptable service for approximately 40 years. If that is true, one might ask, why has this article been written? For several reasons, as will be noted later, but basically the answer is that the rapid expansion of the fertilizer industry during the past 15 years has put a great many tanks into service, many of which are now approaching a critical period in their lifespans. The realities are such at the moment that a major spill of acid from a storage tank could result in efforts by EPA or other agencies to press for restrictive legislation on storage tank construction and inspection. It is, therefore, in the interests of the industry as a whole that the hazards of storing sulfuric acid be fully recognized, made known to those in the industry, and be acted upon where appropriate.

The reality of the situation was illustrated recently with the catastrophic failure in southern Canada of a 3,000 ton tank containing 93% H_2SO_4. This tank, containing 2,700 tons of acid at the time of failure, split from top to bottom on a line coincident with the position of the acid inlet nozzle. The nozzle was located close to the sidewall of the tank and the acid splashing on the wall had eroded the sidewall to only 1/8 in. minimum thickness.

Close examination of the plate in the region of failure revealed vertical grooves about 1/16 in. deep with a spacing of 1/8 in. Figure 1 shows a typical example of such grooving. Thus the effective plate thickness in the grooves was only 1/16 in.

This failure illustrates several important points. First, the tank was built to the API 650 design code and yet the acid inlet was located in a totally unsuitable position for this service. Tanks are still being put into service with this design fault. The need for a design code to be drawn up specifically for sulfuric acid storage tanks is apparent. Second, grooving corrosion was shown to be a hazardous, previously unpublicized form of corrosion in this service. Third, the damage resulting from the ensuing flood of acid (fortunately no people were involved) bore witness to the potential energy stored in a liquid of high density. Two identical tanks were moved from their foundations, cast iron cooler racks demolished, and railcars moved from their tracks.

As a result of this failure, Canadian Industries Ltd. and many other companies undertook urgent inspection programs. From these inspections a picture has emerged of the various types of corrosion found in sulfuric acid storage tanks.

General corrosion

The rate of attack by concentrated sulfuric acid has long been known to be a function of acid strength, acid temperature, and acid velocity. In an acid storage tank, the walls of the tank are heated by the sun and cooled by the wind. In desert areas black bulb temperatures can reach 180°F., so that the color of the tank becomes a factor in determining the corrosion rate! Climatic conditions can therefore

Figure 1. The type of vertical groove found near region of the tank failure.

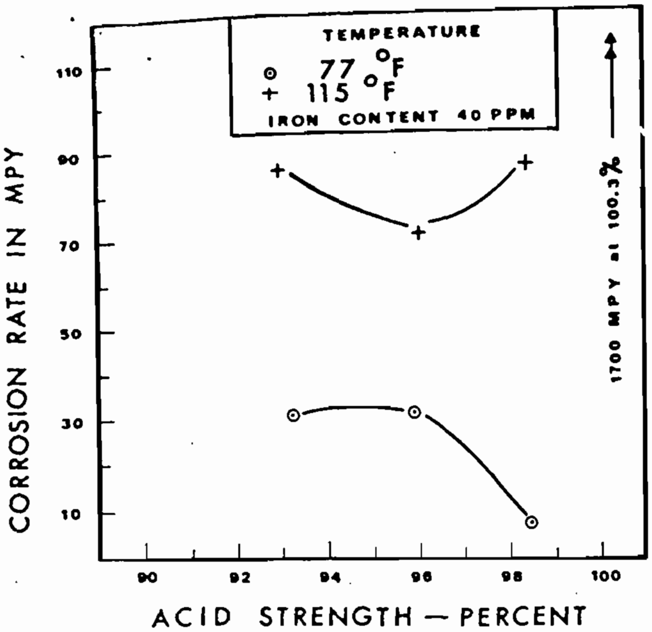


Figure 2. Corrosion rate of carbon steel in concentrated sulfuric acid as a function of acid strength.

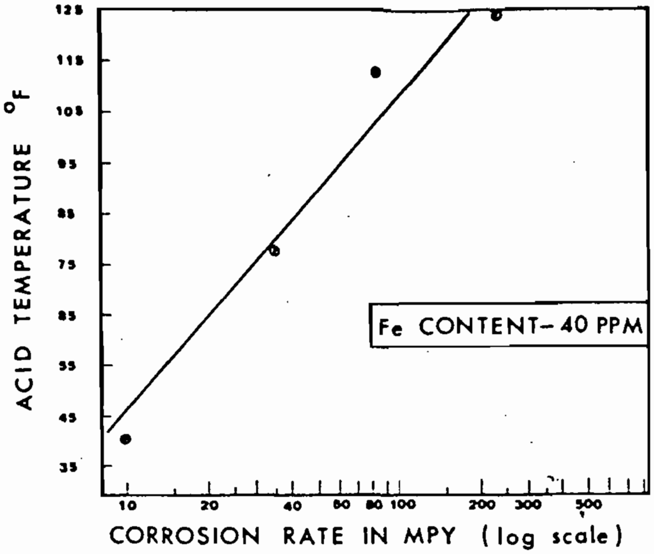


Figure 3. Effect of acid temperature on the corrosion rate of carbon steel in 93.5% sulfuric acid.

be added to the list of corrosion rate determining factors. In addition to all these, two new factors have been identified: the iron contamination level of the acid stored; the copper content of the steel used in the construction of the tank.

In general, the lower the acid strength the more corrosive it becomes, with 77% H_2SO_4 a commonly accepted practical limit for storage in an unprotected carbon steel tank. However, at around 100% strength, sulfuric acid again becomes extremely corrosive. Figure 2 illustrates the influence of acid strength in otherwise identical conditions. This is laboratory data obtained using commercial steel and plant acid with controlled agitation and iron content. Ninety-six per cent strength was chosen as being commonly used for product acid in the European sulfuric acid industry. It is apparent from the data that at 77°F., 98.5% H_2SO_4 is considerably less corrosive than either 93.5 or 96% acid. However, at 100°F., 98.5% acid becomes much more corrosive, approaching the corrosivity of the other two acid strengths examined. The implication of the latter result is to strongly suggest that in cold climates 98% acid only be heated to the minimum temperature sufficient to prevent its freezing.

Figure 3 illustrates the very strong influence of temperature on the corrosivity of 93.5% acid. The practical implications are that good product acid cooling is very important in prolonging tank life, and that in warmer climates the corrosion allowance on a tank has to be increased for a given lifespan. Alternatively, the case for installing anodic protection is greater in warmer climates.

Figure 4 indicates the influence of the level of iron contamination in 93.5% acid on its corrosivity. It is apparent that low iron content acid has a strong affinity for more iron, stronger than acid containing higher iron levels, a fact that was previously unknown. Modern sulfuric acid plants using stainless steel cooling equipment produce acid containing 5 to 10 parts/million iron compared to higher levels, especially in the summer, using cast iron cascade coolers. Therefore, storage tanks may now experience more corrosive conditions than in the past.

It will be noted that the corrosion rates reported in Figures 2, 3, and 4 are significantly higher than previously reported. The tests in this case were carried out in stirred acid. It is believed that previous tests have been carried out in stagnant acid and, as discussed below, the degree of turbulence in a tank will substantially influence its corrosion rate. The data presented here is probably more representative of turbulent areas within the tank or the behavior of a tank with constant recirculation of acid.

Because of better scrap sorting, changes in steel making practice, and tighter specifications for steel plate chemical composition, the level of tramp copper in carbon steel plate has been reduced progressively in the last 20 years. The level is now below 0.1%. It is well known that very small additions of copper to steel markedly affect the corrosion rate of carbon steel in sulfuric acid. When the influence of this variable was studied (*1*), it was concluded that as little as 0.25% copper content in the steel halved corrosion rates in commercial sulfuric acid.

The practical significance of this is that recently constructed storage tanks may corrode faster than tanks constructed in the past. The steel in one 25 year old tank within C.I.L. was recently analyzed at 0.4% Cu. A copper bearing steel was not specified in its construction.

Finally, turbulent acid is considerably more corrosive than stagnant acid. The rate of acid throughput in the tank may, therefore, be expected to influence corrosion rates. In a recent test, a continuously measuring corrosion meter was placed in a 93% acid storage tank. Fluctuations in corrosion rate were recorded between 15 mils/yr. when the contents of the tank were nominally stagnant, and 150 mils/yr. when acid was being simultaneously drawn from and put into the tank.

The rate of general corrosion in a tank can be reduced to very low levels by anodic protection or membrane or brick lining the tank. Anodic protection will reduce the general corrosion rate to typically 3 mils/yr. or less, depending on local circumstances.

A membrane lining, e.g., a baked phenolic resin, if correctly applied and cured, will eliminate corrosion entirely, but has a limited life (5 to 7 years in 93% acid) and cannot be used for 98% acid storage tanks.

Brick lining is an economic solution only for very small tanks.

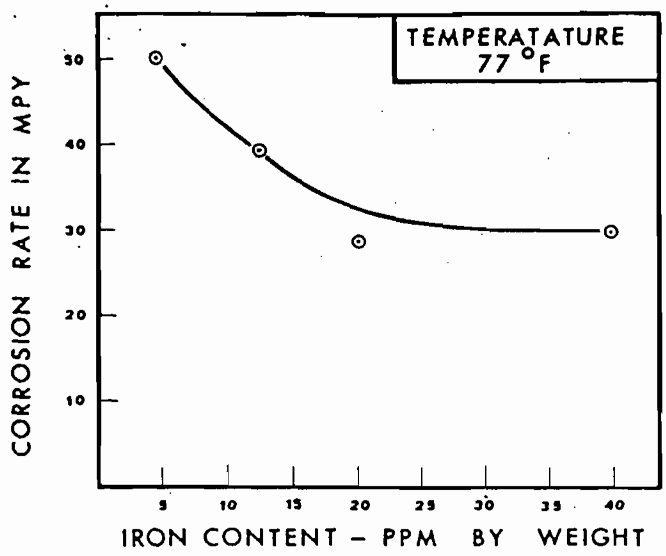


Figure 4. Influence of iron contamination in 93.5% sulfuric acid on its corrosivity to carbon steel.

Erosion/corrosion under acid inlet nozzles

Carbon steel owes its relatively good corrosion resistance in concentrated sulfuric acid to the formation of a soft ferrous sulfate film. When the acid velocity in contact with the steel is high, this soft film is eroded away and high rates of corrosion ensue.

Such is the case when the acid inlet is located too close to the sidewall of the tank and there is no dip pipe. This is a very common error in tank design and it is remarkable that a number of operators have patched the sidewalls of tanks corroded in this way without resiting the acid inlet nozzle. It is also a commentary on the lack of communication between owners, contractors, and tank constructors that the problem was not realized long ago and corrective design changes made.

Figure 5 illustrates the general pattern of thinning and grooving found in the above circumstances.

Fillet welding a patch to the outside wall of the tank is not considered good practice since the fillet weld is then the effective thickness of the tank and cannot be monitored for thickness. Also, it appears that accelerated corrosion takes place between the patch and the original tank wall when this has been breached. The only satisfactory repair is to butt weld new plate into the wall of the tank.

The solution to the problem is simple: to locate the acid inlet-pipe as far from the sidewall as possible, in any case at least eight feet.

Effect of hydrogen

Erosion/corrosion around brackets projecting from the sidewall of the tank is often observed. Some of these are unavoidable, e.g., support brackets for plug valves but all lugs and brackets used in erection of the tank should be cut off and ground flush with the tank wall.

Vertical grooves on the sidewall of a tank under the acid inlet have already been described. Numerous tanks have been reported having this type of corrosion.

It is not possible to detect such grooving from the outside of a tank by ultrasonic examination. Even internal detection of these grooves can be difficult unless the surface is wire brushed clean of rust formed when the tank is washed out. Figure 1 illustrates this point.

Grooving is very commonly found in the side manhole of a storage tank, Figure 6. The severe corrosion at the coverplate flange face is of particular concern. The hitherto commonly adopted solution to the problem has been to replace the manhole nozzle when necessary. A more permanent remedy would be to line the upper half of the nozzle with stainless steel and to use a coverplate clad with stainless steel.

Grooves are also found in side mounted outlets in tanks and in product lines. They have also been observed in cylindrical tanks in rail and barge transports. In all cases, except that of grooving under an acid inlet nozzle, the grooves run circumferentially from the nine o'clock and three o'clock positions to the 12 o'clock position. There is then a deep groove running along the 12 o'clock axis, Figure 6.

The mechanism of this grooving has recently been investigated by C.I.L. Research Laboratories. They have confirmed that hydrogen bubbles produced by corrosion of the steel are responsible for the grooves. The bubbles apparently stream along preferred lines and disrupt the soft protective film locally. Corrosion continues at a high rate along these lines. Figure 7 shows grooving produced on the underside of an inclined plate immersed in 93% acid for several days. No grooving is produced if the bubbles are free to rise clear of the surface on which they are produced. This explains why in a side manhole neck, no grooves are seen in the lower half of the neck.

Since hydrogen produced by corrosion is responsible for grooving, any means by which the general rate of corrosion is reduced will alleviate grooving problems. The use of copper bearing steel in tank construction is claimed to be effective, anodic protection will suppress grooving completely and resin linings are used to prevent grooving by 93% acid in C.I.L. rail cars.

C.I.L. has also observed grooving of the manhole neck in a 20 year old tank containing 50% caustic soda at around 175°F. General corrosion had occurred, generating

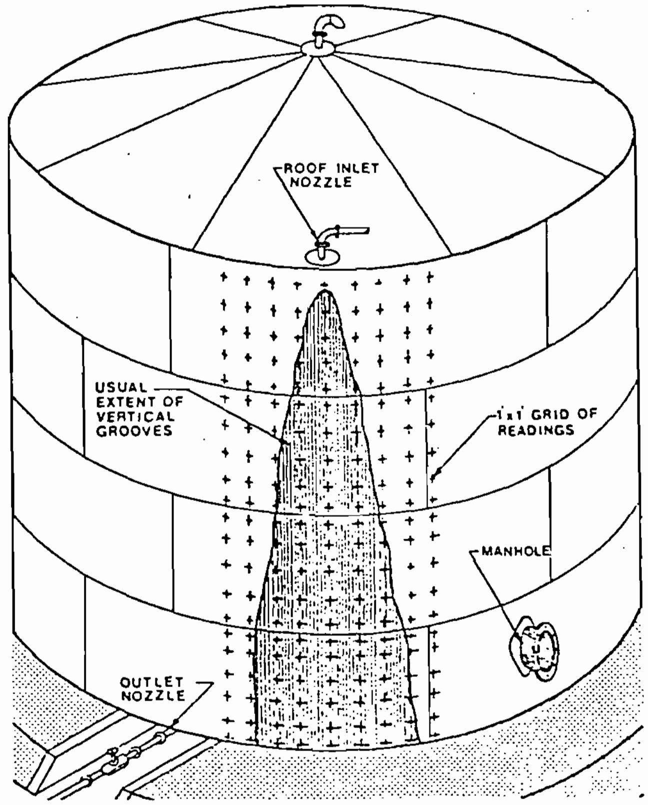


Figure 5. Pattern of thinning and grooving of sidewall under acid inlet nozzle.

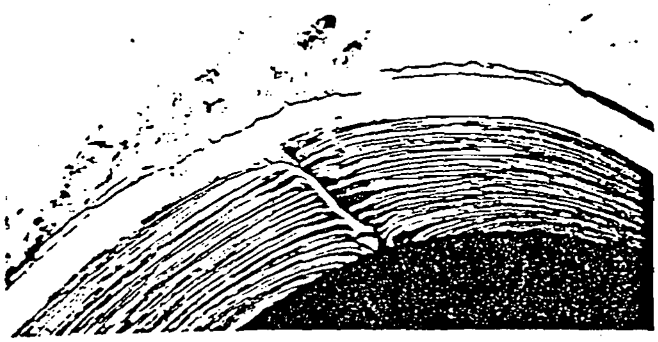


Figure 6. Grooving in the side manhole of a storage tank.

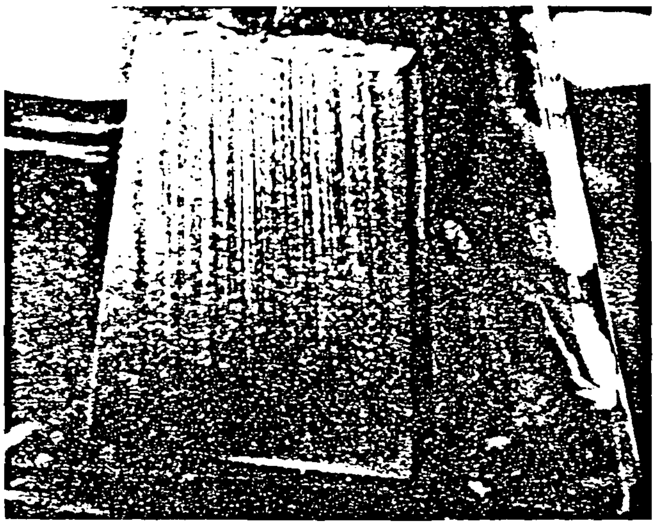


Figure 7. Grooving produced in the underside of an inclined plate immersed in 93% acid for several days.

enough hydrogen bubbles to effect grooving.

Almost all tanks the authors have inspected have had blistering of the floor plates and/or sidewalls. These blisters are usually in the size range 2 to 12 in. in diameter. In some cases they have ruptured and in these cases corrosion takes place at an accelerated rate within the blister.

The explanation for these blisters is well known. In the corrosion process, hydrogen is first produced in atomic form. Two atoms then combine to form a gaseous hydrogen molecule. Some of the hydrogen atoms, however, do not combine to form hydrogen bubbles, but diffuse singly into the steel.

If there is a lamination in the plate then these hydrogen atoms diffuse to the lamination and combine there to form hydrogen gas. This gas is trapped within the plate and pressures of several thousand atmospheres build up slowly until the steel bulges to form a blister and eventually ruptures.

As with hydrogen grooving, blistering can be prevented by suppressing the corrosion reaction producing the hydrogen. Thus, tank lining or anodic protection would be effective. (In an anodically protected tank, any hydrogen is evolved at the cathodes suspended in the acid.)

Ultrasonic examination of plate before tank fabrication would reveal laminations, but this is not proposed as an economic method of preventing blistering in a tank. With a reasonable tank inspection frequency, blisters can be detected and repaired before serious damage occurs. It should be remembered that an unburst blister contains pure hydrogen that will explode if a grinding tool is used. A lamination can be the reason for an abnormally low thickness reading when testing a tank's thickness ultrasonically. A layer of weak, highly corrosive, sulphuric acid can form at the acid/air interface in a tank either by roof openings being left open and rain entering, or simply by "breathing" of damp air into the tank as the acid level falls and absorption of the moisture by the highly hygroscopic acid.

In tanks where there is a large throughput of acid, the weak acid is continually being mixed in with strong acid as acid is discharged into the tank. Also the acid never remains at the same level for very long so attack is never concentrated at one level. However, horizontal grooves have been observed in tanks and some operators are known to have air drying trains attached to the tank vent system. Other operators agitate the contents of the tank either by air sparging or by recirculation of the contents.

The general conclusion is that weak acid attack is only a minor contributor to the overall rate of corrosion of a tank and that special precautions are not warranted for tanks where acid is being added to and drawn from a tank at regular intervals.

Tank linings obviously eliminate weak acid attack and C.I.L. experience of anodic protection system operation is that the passive film formed when the tank is full of acid provides protection for a number of days on the wet walls when the acid level falls.

There are many references in the literature to the effectiveness of anodic protection in reducing the corrosion rate of carbon steel in strong sulfuric acid to very low levels, typically 1 to 3 mils/yr. (*3, 4*) The quality of the acid in terms of iron content is also improved, an important feature where the acid is being marketed either to industries requiring low iron content for product purity such as in alum manufacture or in a market situation in which acid quality can be the key to a sale.

In an anodic protection system, reference electrodes, immersed in the acid, sense the potential of the tank in contact with the acid and feed back the value of this potential to a controller. The control circuit compares this potential value with a preset value and, if necessary, triggers a power stage to apply current to the tank via cathodes suspended in the acid from the tank roof. In this manner the potential of the tank is held continuously in the passive range. The passive film remains intact even when acid drains from the tank and is reinforced very quickly when the tank is refilled. Only water washing of the tank would completely destroy the passive film. Power consumption is minimal and maintenance costs are very low.

Figure 8 shows the comparative corrosion rates of anodically protected and unprotected carbon steel exposed at various heights in a 10,000 ton, 93% acid storage tank. Of interest is that the ratio between protected and unprotected corrosion rates remains virtually unchanged from the tank base, where specimens were continuously immersed, to the upper levels where fluctuation in acid level left specimens alternately immersed and exposed to humid air drawn into the tank. This bears out the assertion that the passive film remains intact when acid drains from the tank.

In a tank of this size, assuming acid remained in the tank for an average of one week, this protected corrosion rate would correspond to an iron pickup of 1 to 2 parts/million.

Membrane liners can be used for protecting storage tanks. The only satisfactory resin linings (other than TFE) for service in concentrated sulfuric acid are the so-called high bake phenolic resins. These are generally used in the unmodified version. The coating is hand sprayed to a total thickness of 5 to 8 mils in three to four coats. It is finally cured at 380 to 400°F., hence the term "high bake."

This bake presents substantial problems for large tanks in that it is difficult to ensure even heating of the tank surfaces, particularly getting the floor hot enough to cure. The tank, of course, has to be completely insulated for the baking operation.

There may be problems due to flexing of the floor in large diameter tanks. (2)

There appears to be some doubt of the upper limit of acid concentration that can be brought into contact with the cured resin without its charring. Ninety eight per cent probably represents a safe limit that effectively precludes its use in so-called "98 percent" storage tanks, which may range from 98 to 99% in acid concentration.

In 93% acid, a lining life of 5 to 7 years can be expected, but close attention must be paid to quality control when the lining is applied if premature failure is to be avoided.

It has becomes apparent from recent inspections that the requirements for sulfuric acid tank inspection in terms of frequency and thoroughness of examination are more stringent than many companies have adopted to date. C.I.L. recently revised its procedures for tank inspections in the light of recent experience. This procedure lists the various types of corrosion that have to be looked for and specifies the schedule of ultrasonic thickness checks. Where the acid inlet nozzle is within 8 ft. of the sidewall, a 1 ft. square grid is used for ultrasonic thickness measurements using the acid nozzle as the centerline and extending at least 4 ft. around the sidewall of the tank in both directions. Additionally, readings at 1 ft. vertical intervals are taken from the top to bottom of the tank at 90°, 180° and 270° using the acid nozzle as the 0° position. The essential need for thorough internal inspection is stressed. An external inspection is specified every two years and an internal one every five years. The latter would be more frequent if the tank was located in warmer climates than those in which C.I.L. operates.

In North America, sulfuric acid storage tanks are constructed on the basis of API 650, a code which was drawn up for the construction of oil storage tanks. There is considerable evidence that this code needs to be amended specifically for construction of sulfuric acid tanks.

C.I.L./Chemetics have drawn up such a specification for their own use. It is based on API 650, Appendix D but has significant deviations from that base. These deviations were intended to make use of higher strength steels, to eliminate safety hazards such as acid inlet nozzle placing, and in general to cater for the storage of a dense, corrosive, and highly hazardous fluid.

In summary

Sulfuric acid storage tanks are subject to several types of corrosion, each of which can be substantially reduced or eliminated either by changes in design or introduction of a protection system as part of the tank design.

Recent events indicate a need for increased internal inspection of sulfuric acid storage tanks and for revision of API 650, Appendix D to suit the specific requirements of storing sulfuric acid rather than oil. It is considered that an urgent industry initiative is required in this respect as a major tank failure involving such a hazardous fluid *must* be avoided. #

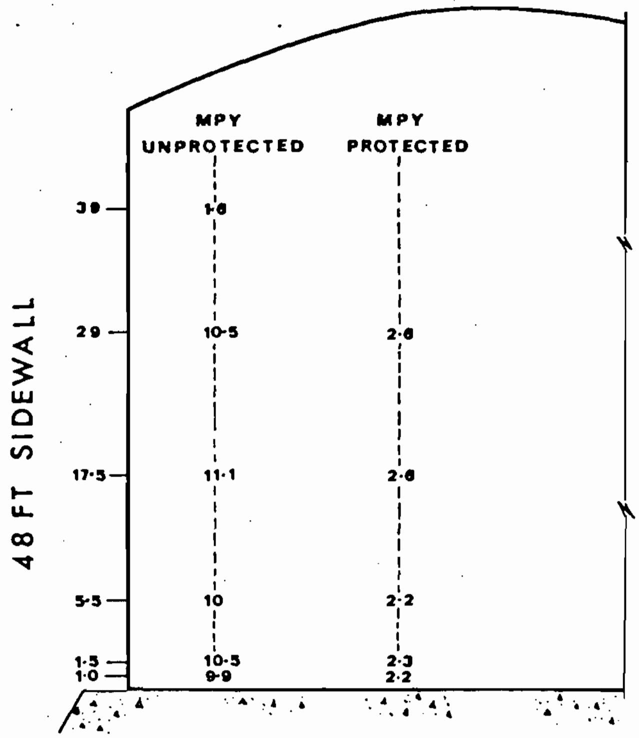


Figure 8. Effectiveness of anodic protection in a 93% sulfuric acid storage tank.

Literature cited

1. Nelson, G. A., *Mats. Prot.*, 3, 24 (1963).
2. "Coatings and Linings for Immersion Service," NACE TPC Publication No. 2.
3. *Mats. Prot.*, 5, 69 (September, 1963).
4. Hays, L. R., *Mats. Prot.*, 5, 46 (September, 1966).

D. Fyfe, technical manager, Chemetics International, Ltd., earned his M.A. in metallurgy from Cambridge Univ. and his Ph.D. in corrosion engineering from London Univ., both in the United Kingdom. He specializes in the development of new technology for the acid manufacturing industries.

R. Vanderland, a technical sales representative with Chemetics International Ltd., earned his diploma in industrial instrumentation from Centennial College, Toronto, Ontario.

J. Rodda, a senior technician with Chemetics International Ltd., was educated at Technical High School, Sudbury, Ontario. At present, he is directing laboratory work relevant to the company's activities in the acid industry.

Clair Fancy

LANDERS & PARSONS, P.A.

ATTORNEYS AT LAW

CINDY L. BARTIN
DAVID S. DEE
JOSEPH W. LANDERS, JR.
JOHN T. LAVIA, III
FRED A. McCORMACK
PHILIP S. PARSONS
ROBERT SCHEFFEL WRIGHT

HOWELL L. FERGUSON
OF COUNSEL

VICTORIA J. TSCHINKEL
SENIOR CONSULTANT
(NOT A MEMBER OF THE FLORIDA BAR)

310 WEST COLLEGE AVENUE
POST OFFICE BOX 271
TALLAHASSEE, FLORIDA 32302
TELEPHONE (904) 681-0311
TELECOPY (904) 224-5595

January 16, 1997

RECEIVED
JAN 17 1997
BUREAU OF
AIR REGULATION

Mr. Douglas Beason, Esq.
Office of General Counsel
Department of Environmental
Protection
2600 Blair Stone Road
Twin Towers Office Building
Tallahassee, Florida 32399

Re: Piney Point Phosphates, Inc. (PSD-FL-144)

Dear Mr. Beason:

As you know, this law firm is helping the Board of County Commissioners of Manatee County ("County") with its evaluation of various environmental law issues concerning a proposal by Piney Point Phosphates, Inc. ("Piney Point"), to refurbish and restart a fertilizer manufacturing facility in Manatee County that was closed several years ago. Based on the correspondence to and from the Florida Department of Environmental Protection ("DEP"), which is attached hereto as Exhibits "A" and "B," it is our understanding that Piney Point met with DEP on December 10, 1996 to determine whether Piney Point may rebuild its existing sulfuric acid plant and then resume commercial operations, without obtaining any additional permits, permit modifications, or other approvals from DEP. It also is our understanding that DEP has not yet made a final determination about the permitting requirements that are applicable to Piney Point's plan.

This letter describes Manatee County's concerns about Piney Point's proposal.

I. SUMMARY

Piney Point's sulfuric acid plant was built before 1975. The plant was used sporadically in the 1980's. The plant "was down for major repairs and maintenance in February 1989" and, later that year, Piney Point submitted an application to DEP for authorization to construct a new sulfuric acid plant, which would permanently replace the existing plant. The existing plant closed in 1992 and has not resumed operations since that time. In the interim, Piney Point has pursued the DEP permits for its new plant.

In 1996, the U. S. Park Service and Manatee County alerted DEP that Piney Point had not conducted a proper "top-down" analysis of the Best Available Control Technology ("BACT") for Piney Point's new facility. Manatee County submitted a BACT analysis to DEP which demonstrated that the emissions limitations for Piney Point's new facility should be more restrictive than the emissions limitations that were proposed by Piney Point. Now it appears that Piney Point is prepared to abandon its plan to build a new sulfuric acid plant.

Piney Point now plans to spend $18,000,000 or more to rebuild and restart its old sulfuric acid plant. Substantial portions of the plant will be replaced. The magnitude of these repairs suggests that the plant currently is inoperable or, at best, unable to operate at its design capacity.

Piney Point's submittal to DEP does not adequately address the permitting issues that must be evaluated before DEP can determine whether Piney Point's proposal will trigger the application of various state and federal regulations, such as New Source Performance Standards ("NSPS") and Prevention of Significant Deterioration ("PSD"). Based on the limited information available at this time, it appears that Piney Point's plan to rebuild the existing sulfuric acid plant:

(a) may constitute a "reconstruction" of the facility, subject to NSPS requirements;

(b) will cause an increase in hourly emissions, subject to NSPS requirements for a "modification"; and

(c) will cause a significant net increase in annual emissions, subject to PSD requirements for a "major modification."

Under the applicable regulations, these issues must be addressed and resolved before Piney Point commences construction on the existing plant.

Manatee County respectfully requests DEP to carefully review all of the relevant facts and regulations before DEP makes any decisions concerning Piney Point's proposal to rebuild its sulfuric acid plant in Manatee County. The County also requests DEP to provide Manatee County with:

> (a) written notice of any DEP decision concerning any proposal by Piney Point to construct, modify, refurbish, or operate any potential source of pollution at Piney Point's facility in Manatee County; and
>
> (b) a clear point of entry into the administrative hearing process whenever DEP makes any determination concerning the applicability of any DEP regulations to Piney Point's facility.

Manatee County wants to work in a cooperative manner with DEP and Piney Point to evaluate the issues concerning Piney Point's proposed activities in Manatee County. However, Manatee County also wants to be positioned to exercise its legal rights and protect its substantial interests, if necessary.

All of these issues are discussed in more detail in the following sections of this letter.

II. FACTUAL BACKGROUND

Piney Point's existing sulfuric acid plant was built before 1975. The plant originally used a single absorption process to produce 1400 tons per day ("tpd") of sulfuric acid.[1] In 1975, DEP issued a construction permit that authorized the plant's owner to increase the plant's capacity to 2000 tpd and convert the plant to a double absorption process. This modification was completed by August 1976.[2]

---

[1] "Report In Support Of An Application For A PSD Construction Permit Review" prepared by Koogler & Associates for Royster Phosphates, Inc. (dated November 30, 1989) at page 4.

[2] Id.

We do not know whether there have been any modifications of the sulfuric acid plant since 1976. However, the former owner of the plant reported that:

> the sulfuric acid plant was down for <u>major repairs</u> and maintenance in February 1989, for approximately 415 hours.[3] (emphasis supplied).

In November 1989, the owner of the plant (i.e., Royster Phosphates, Inc., or "Royster") submitted an application to DEP for a permit to construct a new sulfuric acid plant. The permit application repeatedly states that the existing sulfuric acid plant "will be permanently shutdown when the new sulfuric acid plant is operational."[4]

The existing sulfuric acid plant was shutdown in 1992 and has not operated for more than four years.[5] Indeed, the operations of the plant have been sporadic since 1984. The 1989 permit application for the new facility states that 1984

> was the only year of full plant operation in the previous several years at the time of [PSD permit] application was submitted [sic] in 1989.[6]

Most recently, the plant's operations increased from 1988 (3982 hours) to 1990 (7875 hours), but then declined until 1992 (3410 hours), when the plant was closed.[7]

---

[3] Letter from Koogler & Associates to DEP (dated October 2, 1990) at page 2.

[4] "Report In Support Of An Application For A PSD Construction Permit Review" at pages 1 and 4.

[5] Letter from Koogler & Associates to DEP (dated April 24, 1995), Attachment 1 at page 1, §1.1.

[6] Letter from Koogler & Associates to DEP (dated October 2, 1990) at page 1.

[7] Letter from Koogler & Associates to DEP (dated April 24, 1995), Attachment 1 at page 1, §1.1.

The sulfuric acid plant and the related fertilizer manufacturing facilities have been owned by a succession of different companies. It is our understanding that Piney Point bought the facilities after the bankruptcy of the prior owner, Royster Phosphates, Inc.

The physical and operational condition of Piney Point's plant was suspect even before the plant shut down. Among other things, in 1989 a spill of sulfuric acid created a cloud of airborne pollutants, which compelled Manatee County to evaluate approximately 400 people from the area near the plant. Industrial accidents at the site have resulted in several injuries and deaths.

In a letter to DEP dated December 17, 1996, Piney Point identified "approximately 90% of the repair activities associated with the repair and restart" of the existing sulfuric acid plant.[8] Piney Point "anticipates expending approximately $18 million [$18,000,000] effecting these repairs."[9] According to Piney Point, "several plant components are currently proposed to be physically relocated" and, "due to technical obsolescence, some of the existing equipment or repair components are no longer available."[10] Piney Point's list of changes to the plant indicates that many components of the facility must be replaced completely (e.g., the boiler feedwater heater; the economizer; all three acid towers; all three mist eliminators; a heat exchanger; the condensate storage tank; the cooling tower; the acid coolers; the acid pump tanks; nine pumps; sixteen ducts; etc.).[11] Piney Point alleges in its letter that these "repairs" will not affect the plant's production capability or emissions, but Piney Point does not identify the production capability or emissions levels that it is using as the baseline for its comparison.

---

[8] Exhibit "A" at page 2.

[9] Id.

[10] Exhibit "A" at page 1.

[11] Exhibit "A", at pages 1-3 of Exhibit I.

III. MANATEE COUNTY'S CONCERNS

Manatee County believes that Piney Point's proposed work on the existing sulfuric acid plant may constitute a "reconstruction," "modification," or "major modification" of the facility, which would trigger the application of NSPS and PSD requirements. Each of these issues is discussed separately in the following sections of this letter.

This letter primarily focuses on the regulations in the federal NSPS and PSD programs, which have been adopted by reference in DEP's rules, because the U. S. Environmental Protection Agency's ("EPA") interpretations of the applicable federal regulations are more numerous and easier to locate than DEP's precedents.

A. Reconstruction Issues

We assume that Piney Point sent its letter to DEP ("Exhibit A") in part because Piney Point does not want its work on the existing sulfuric acid plant to be classified as a "reconstruction." Reconstruction is defined at 40 CFR 60.15(b)[12] as follows:

> (b) "Reconstruction" means the replacement of components of an existing facility to such an extent that:
>
> > (1) The fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility
> > . . .

---

[12] DEP Rule 62-204.800(7)(d), F.A.C., states that "the general provisions of 40 CFR Part 60, Subpart A, revised as of July 1, 1994, are adopted and incorporated by reference" into the DEP rules, subject to certain exceptions that are not relevant here. Thus, the federal definition and general provisions concerning a "reconstruction" apply to facilities in Florida.

If a reconstruction occurs, the plant "becomes an affected facility, irrespective of any change in emission rate." (emphasis supplied) 40 CFR 60.15(a).

In this case, Piney Point's letter does not contain enough information for DEP to determine whether a reconstruction will occur. First, Piney Point's letter does not identify all of the work and all of the costs associated with Piney Point's proposed project. Piney Point's letter acknowledges that the attached list of "repairs" includes only "approximately 90%" of the work that will be done on the existing sulfuric acid plant. Piney Point should be asked to identify all of the proposed changes to its existing plant and identify the anticipated costs associated with each of the proposed changes.

Second, Piney Point's letter and the attached affidavit appear to be based on an erroneous premise. The affidavit states that the cost of the work on the existing plant was compared to the cost of

> a new grassroots plant of the same capacity (2,000 TPD), design (double contact wet process) and emissions limitations. . . . (emphasis supplied).[13]

It is our understanding that Piney Point's existing plant does not use a "wet" process. A "wet gas plant" uses hydrogen sulfide as the source of sulfur.[14] Consequently, Piney Point's estimate of the cost of a comparable new facility may be in error.

Third, Piney Point's letter and affidavit do not indicate whether Piney Point's estimate includes the cost of modifications to the plant that have occurred in the past. To determine

---

[13] Letter dated December 17, 1996 from Piney Point, at Exhibit II.

[14] See §8.10 EPA Compilation of Air Pollutant Emission Factors, Volume 1 (5th Ed.); AP-42 (January 1995).

whether the work on Piney Point's plant constitutes reconstruction, Piney Point must calculate the cost of the changes that are currently proposed and add them to the cost of all of the changes that have occurred at the plant in the past.[15] The current proposals cannot be viewed in isolation.

Fourth, Piney Point's letter and affidavit are too conclusory in nature. Piney Point did not provide a detailed, itemized estimate of the cost of its proposed project or the cost of a new facility. Without itemized estimates, DEP cannot determine whether Piney Point's conclusions are valid.

Manatee County believes DEP should request additional, detailed information from Piney Point so that DEP can better evaluate Piney Point's proposal. Additional information is particularly important in this instance because Piney Point's estimated capital cost for this project (i.e., $18,000,000) is approaching 50% of the estimated cost of a new facility (i.e., $40,000,000) and thus it appears that Piney Point is approaching the regulatory threshold for a reconstruction. In addition, Piney Point should not be allowed to avoid the requirements associated with a reconstruction unless Piney Point can clearly demonstrate that its project does not constitute a reconstruction.

B. Modification Issues

Piney Point's letter to DEP does not directly address many of the issues that must be answered before DEP can determine whether Piney Point's activities constitute a "modification" that is subject to NSPS or PSD requirements.

---

[15] See generally letter from EPA to David S. Dee (dated August 24, 1996), which is attached hereto as Exhibit "C", at pages 3-4 (to determine whether changes to Tampa's resource recovery facility constituted a reconstruction, EPA requested Tampa to submit information concerning all costs of changes for each emissions unit from the time of initial startup in 1967 to the present).

1. NSPS Determination of a Modification

For NSPS analyses, 40 CFR 60.14(a)[16] provides as follows:

> Except as provided under paragraphs (e) and (f) of this section, any physical or operational change to an existing facility which results in an increase in the emission rate to the atmosphere of any pollutant to which a standard applies shall be considered a modification within the meaning of section 111 of the [Clean Air] Act. Upon modification, an existing facility shall become an affected facility for each pollutant to which a standard applies and for which there is an increase in the emission rate to the atmosphere.

Thus, as a general rule, any change that causes any increase in regulated emissions shall constitute a modification subject to NSPS requirements. The cost of the changes is not relevant to the determination of whether the changes are a modification.

There are exceptions to this general rule, but the exceptions do not apply to Piney Point's proposal. Most significantly, 40 CFR 60.14(e)(1) provides that routine "maintenance, repair, and replacement" is not a modification. This exception is not applicable here because the extensive changes proposed by Piney Point are not "routine." Indeed, many major components of the plant must replaced completely, including the boiler feedwater heater, the economizer, all three acid towers, all three mist eliminators, a heat exchanger, the condensate storage tank, the cooling tower, the acid coolers, the acid pump tanks, nine pumps, and sixteen ducts. The sheer magnitude of these replacements, together with the estimated minimum cost of $18,000,000, highlights the fact that Piney Point's proposed activities are not "routine."

---

[16] The provisions of 40 CFR 60.14 are adopted by reference in DEP Rule 62-204.800(7)(d), F.A.C.

For NSPS purposes, emissions increases are determined by comparing the plant's hourly emission rate immediately before and after the physical or operational changes to the plant.

> The EPA compares the hourly emissions of the unit at its current maximum capacity to its potential emissions at maximum capacity after the change. . . . In this calculation, the agency disregards the unit's maximum <u>design</u> capacity; this factor often sheds little light on the unit's <u>actual current</u> capacity to produce emissions." (emphasis in original)

<u>Wisconsin Electric Power Company v. Reilly</u>, 893 F.2d 901, 913 (7th Cir. 1990) (herein referred to as "<u>WEPCO</u>"). When establishing a plant's actual current capacity, EPA does <u>not</u> consider the plant's original design capacity. <u>Id</u>. Similarly, EPA does <u>not</u> establish the pre-renovation emissions of a plant by looking at "representative" emissions during prior years. <u>WEPCO</u> at 913-915. Baseline emission rates for the plant "are determined by hourly maximum capacity just prior to the renovations." <u>WEPCO</u> at 914.

Given the extensive changes that must be made to Piney Point's sulfuric acid plant before the plant can resume commercial operations, it is clear that the plant is in a state of considerable disrepair. We assume that, in its current deteriorated condition, this 1976 vintage plant is not capable of operating at its design capacity or complying with the applicable DEP emissions limitations. Indeed, the plant may not be capable of operating at all, unless the plant undergoes extensive non-routine repairs and improvements. Consequently, for NSPS purposes, the plant's "actual current capacity" appears to be zero. If so, Piney Point's non-routine changes to the plant will increase the plant's emissions, which will constitute a modification, which will make the plant subject to NSPS requirements.

If Piney Point contends that the plant can operate in its current condition, DEP should require Piney Point to conduct stack tests to establish the plant's "actual emissions." Without current stack test data, DEP cannot accurately determine whether the proposed changes to the plant will cause an emissions increase.

2. PSD Determination of a Modification

In accordance with 40 CFR §52.21(i)(2), the federal PSD and New Source Review (NSR) requirements apply to new sources of air pollution and "major modifications" of existing sources.[17] A "major modification" is defined as

> any physical change in 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 [Clean Air] Act.

40 CFR §52.51(b)(2)(i).[18] A "net emissions increase" is defined as the sum of "any increase in actual emissions from a particular physical change," together with any other "contemporaneous" increases or decreases in actual emissions. 40 CFR §52.21(b)(3). An increase or decrease in emissions is "contemporaneous" if

> it occurs between: (a) the date five years before construction on the particular change commences; and (b) The date that the increase from the particular change occurs.

40 CFR §52.21(b)(3)(ii).

These federal PSD regulations were described and applied by the U.S. Environmental Protection Agency ("EPA") in a 1992 memorandum (attached hereto as Exhibit "D") concerning the Cyprus Northshore Mining Corporation ("Cyprus"). In pertinent part, EPA explained that:

> Applicability of the PSD provisions must be determined in advance of construction and on a pollutant-by-pollutant basis. Specifically, to determine whether a proposed change at an existing source will result in

[17] The federal PSD and NSR requirements have been adopted by DEP in Rule 62-212.400, F.A.C.

[18] Under the PSD regulations, a major modification does not include "routine maintenance, repair and replacement." 40 CFR §52.21(b)(2)(iii)(a). This exemption does not apply here because Piney Point's project involves non-routine repairs and replacements.

> an increase in actual emissions, the source must first determine a baseline level of actual emissions. The applicable regulation defines actual emissions on a particular date as "the average rate, in tpy, at which the unit actually emitted the pollutant during a 2-year period which precedes the particular date and which is representative of normal source operation" [see 40 CFR 52.21(b)(21)(ii)]. The Administrator shall allow use of a different time period "upon a determination that it is more representative of normal source operation." [Ibid.] The EPA has "typically used the 2 years immediately preceding the physical or operational change to establish the baseline" [see 57 FR 32317].[19]

In the <u>Cyprus</u> case, EPA rejected Cyprus' argument that the baseline emissions could be established by looking at the facility's emissions before the "contemporaneous" period (i.e., more than five years before the proposed change to the facility). EPA explained its decision in the following terms:

> The EPA policy presumes a calculation based on the 2 years that immediately preceded the changes [see 45 FR 52676, 52705, 52718 (1980)].
>
> *   *   *   *   *   *
>
> As discussed, the Administrator's power to use a different baseline period is limited to those circumstances where the source demonstrates that some time period other than the 2 years that precede the change is more representative of normal source operation. In general, EPA has indicated that this provision is to apply to catastrophic occurrences such as strikes and major industrial accidents. . . .

---

[19] Exhibit "D" at page 3.

* * * * * *

> On the other hand, EPA has declined to consider a stop in operations, in and of itself, to constitute grounds to change the baseline years. For instance, in the WEPCO rulemaking, EPA adopted a presumption for utilities that considers any 2 years within the 5 years that precede the change to be representative of normal source operations. However, EPA rejected comments seeking to allow further accommodations for units that had been out of operation [see 57 FR 32325].
>
> > The EPA disagrees with comments seeking to allow the use of any 2 consecutive years within the last 5 years of a unit's "operation" rather than within the 5 years directly preceding the proposed change. A shifting of the 5-year period would be difficult to harmonize with the definitions of contemporaneous contained in the regulations. This type of open-ended provision would even credit a unit which has been inoperative for 20 or 30 years or longer with a high level of emissions.[20]

In light of these considerations, EPA concluded that the baseline emissions for some of Cyprus' units were zero. EPA noted that:

> in the last 10 years the source [Cyprus] has been idle due to general economic conditions, and the zero source baseline appropriately reflects source utilization under these longstanding market conditions.[21]

---

[20] Exhibit "D" at pages 7 and 8.

[21] Exhibit "D" at page 8.

EPA rejected Cyprus' argument that Cyprus could calculate the facility's net emissions increases and decreases by looking at emissions changes that occurred outside the 5 year period for "contemporaneous" changes.[22] EPA noted that Cyprus' argument conflicts with the plain language of EPA's regulations.

> Moreover, allowing credit for very old emissions reductions undermines the purpose of the contemporaneous requirement by enabling new construction activity to burden the environment with levels of air pollution higher than they have been for many years.[23]

If we apply the EPA regulations and <u>Cyprus</u> analyses to the Piney Point proposal, it appears that Piney Point's baseline emissions are zero and any significant increase in emissions will trigger New Source Review requirements.

As noted in <u>Cyprus</u>, EPA's policy is to calculate "actual emissions" by looking at the facility's average emissions during the preceding two years. In this case, Piney Point's average emissions during the past two years have been zero.

EPA can consider a different baseline period, but EPA has indicated in <u>Cyprus</u> that a different baseline should be established only when there has been a "catastrophic" occurrence. In this case, Piney Point has not alleged and presumably cannot demonstrate that a catastrophic event has occurred.

Piney Point's decision to stop its operation for economic reasons is not sufficient justification to change the baseline years. Here, as in the <u>Cyprus</u> case, "the zero baseline appropriately reflects source utilization."[24]

Even if we consider Piney Point's emissions during the last five years, Piney Point's "actual emissions" will be quite small. In this hypothetical case, Piney Point's "actual emissions" are the "average rate, in tpy [tons per year] at which the unit actually emitted the pollutant during a 2-year period." Since

---

[22] Exhibit "D" at pages 6 and 7.

[23] Exhibit "D" at page 7.

[24] Exhibit "D" at page 8.

Piney Point's plant was not in operation for approximately 4.5 of the last 5 years, the average emissions rate for any two year period will include, at most, only about six months of emissions.

The baseline emissions rate for Piney Point's plant will be compared to the plant's potential to emit after the modification is completed. Since the plant previously was a major source, it seems highly probable that there will be a "significant" net emissions increase if Piney Point rebuilds its sulfuric acid plant and then operates the plant at its previously permitted levels. If there is a significant increase, the plant will be subject to PSD review pursuant to state and federal regulations.

C. PSD Review for Shutdown Facilities

Under EPA policy, a facility that has been shutdown for two years or more is presumed to be shutdown on a permanent basis. A facility that has been permanently shutdown must undergo PSD review as a new source before resuming operations. See also §62-210.300(6)(b), F.A.C.

EPA's policy and presumption should be applied in this case. Piney Point and its predecessors have stated since at least 1989 that they intended to "permanently shutdown the existing facility" as soon as the new sulfuric acid plant is available. Given the extensive non-routine repairs that are required to the existing plant, it appears that Piney Point intentionally allowed the old, existing plant to deteriorate over the past five years while Piney Point pursued the permits for the new facility. Since Piney Point cannot simply reactivate the existing plant and instead must rebuild it, Piney Point should not be allowed to evade the requirements for new sources nor should Piney Point be allowed to renew its operations at old, high levels of emissions.

IV. CONCLUSION

Manatee County would like to work with DEP to evaluate the issues that have been raised by Piney Point's proposal to rebuild the existing sulfuric acid plant. At this time, however, Manatee County and DEP do not have enough information to properly analyze Piney Point's proposal. For this reason, Manatee County respectfully requests DEP to take all appropriate steps to ensure that DEP has all of the relevant facts in hand before DEP makes any final determinations concerning the applicability of DEP's regulations to Piney Point's facility.

Manatee County also again respectfully requests DEP to provide Manatee County with written notice whenever DEP reaches any conclusions about the application of the NSPS and PSD regulations to Piney Point. Please note that Manatee County is entitled to notice and a clear point of entry into the administrative process, even if DEP decides that the NSPS or PSD regulations do not apply in this instance. See Manasota-88 v. Gardinier, Inc., 481 So. 2d 948 (Fla. 1st DCA 1986)(Manasota-88 is entitled to an administrative hearing to contest DEP's decision that an air permit is not required); Friends of the Hatchineha, Inc., v. Department of Environmental Regulation, 580 So. 2d 267 (Fla. 1st DCA 1991)(environmental group entitled to administrative hearing to challenge DER's decision that proposed driveway qualified for exemption from dredge and fill permitting process). Although Manatee County does not wish to engage in litigation with DEP, Manatee County does wish to preserve its right to pursue its administrative remedies, if necessary.

Thank you for your cooperation and assistance with this matter. Please call me if you have any questions. Manatee County would be happy to meet with DEP in Tallahassee or Tampa, at your convenience, to discuss these issues in more detail.

Sincerely,

David S. Dee

David S. Dee

cc: Dr. Richard Garrity
Bill Thomas
Gerald Kissel
Howard Rhodes
Clair Fancy
Brian Beals, EPA
Scott Davis, EPA
Joyce Chandler, EPA OECA
Ellen Porter, National Park Service
Mike Solomon, EPA
Hamilton Rice, Jr.
Karen Collins
Paul Amundsen
Richard Moore

PINEY POINT PHOSPHATES, INC.

13300 U. S. Hwy. 41 North
Palmetto, Florida 34221
(941) 722-4555

<u>CERTIFIED/RETURN RECEIPT NO. P 576 124 740</u>

17 December 1996

Mr. W. C. Thomas, P.E., Administrator
State of Florida
Department of Environmental Protection
Division of Air Resources Management
Southwest District Office
3820 Coconut Palm Drive
Tampa, FL 33619

Re: Piney Point Phosphates, Inc.;
FDEP Permit No. A041-197112
Sulfuric Acid Plant

Dear Sir:

Piney Point Phosphates, Inc. (PPP) appreciates the opportunity and time you gave Company representatives on 10 December 1996 to discuss the forthcoming restart of the above-referenced sulfuric acid plant. As you may recall, PPP intends to repair the existing 2,000-ton-per-day sulfuric acid plant for restart in late 1997. PPP has identified several specific areas that will be repaired or equipment replaced to different configurations.

Due to technical improvements and safety considerations, several plant components are currently proposed to be physically relocated during repairs. PPP does not anticipate that these actions will in any way affect the plant production capability or alter the emissions from the source. Further, due to technical obsolescence, some of the existing equipment or repair components are no longer available.

Concomitant with the sulfuric acid plant repair will be repairs to the Sulfur Storage Tank operated under FDEP permit AO41-206854. PPP does not anticipate any changes in emissions or operations rate in this source after repairs.

EXHIBIT
A

PPP will also be installing an auxiliary boiler that is currently permitted under FDEP permit AC41-232096.

Attached as "Exhibit I" find a list and short description of the repairs. These repairs represent approximately 90% of the repair activities associated with the repair and restart. PPP anticipates expending approximately $18 million effecting these repairs, including installation of a new Sulfur Storage Tank and auxiliary boiler ($16 million without these later two items).

PPP has reviewed these repair costs in contrast to constructing a new grassroots sulfuric acid plant and found the costs to be less than 50% of an entirely new plant. Find as "Exhibit II" a professional engineer's certification of the estimated repair costs and estimated new plant costs associated with this project. Repairs will be made primarily by Monsanto Enviro-Chem Systems, the original designer and builder of the original plant.

In closing, we appreciate your taking time to discuss this matter with our representatives. Please consider the attached exhibits and foregoing information; then if further information or response is needed, please contact me. Thank you.

Sincerely,

Ivan Nance

Ivan Nance
Corporate Environmental Manager

/rmm

Attachments

bcc: R. Stewart
R. Moore
C. Masio
T. Baroody

EXHIBIT I

PROPOSED REPAIRS AND EQUIPMENT REPLACEMENT TO THE EXISTING SULFURIC ACID PLANT AT PINEY POINT

Note: These are the major repairs that are planned. They are not all inclusive, but comprise about 90% of the work that is proposed.

1. Sulfur Burner: The existing unit will be retained and repaired.

2. Boiler Feedwater Heater: A new heater of same size and similar design will replace the existing unit that will be demolished.

3. Waste Heat Boilers: The two (2) existing boilers will be retained and repaired.

4. Economizer: A new economizer of larger size and similar design will replace the existing unit which will be demolished.

5. Main Compressor: The existing compressor will be retained and refurbished.

6. No. 1 Converter: The existing unit will be retained. The 1st pass section (of four passes) will be replaced with high temperature materials. The remaining passes will be retained and refurbished. Catalyst will be replaced as necessary.

7. No. 2 Converter: The existing unit will be retained and the converter floor repaired. All catalyst will be replaced.

8. Acid Towers: All three (3) acid towers (drying, interpass absorption and final absorption) will be replaced with smaller size units of similar design and higher efficiency. The existing towers will be demolished. Two (2) towers will be relocated from on-top of the control room to separate free standing foundations.

9. Mist Eliminators: New mist eliminators will be provided in all three of the new towers.

10. Heat Exchangers: One new heat exchanger of smaller size and similar design will replace the existing unit that will be demolished. Two existing heat exchangers will be retained and repaired.

11. Superheater:	The existing unit will be retained and repaired.
12. Condensate System:	A new condensate storage tank of larger size, similar design and different metallurgy will replace the existing unit that will be demolished. The condensate system will be of similar design.
13. Cooling Tower:	A new tower of smaller flow and similar design of higher efficiency will be installed in the area occupied by the previous unit, which was previously destroyed in a storm.
14. Acid Coolers:	New coolers of a new design (shell & tube anodic protection) will replace the existing cast iron coolers which will be demolished.
15. Acid Pump Tanks:	The two (2) existing pump tanks will be replaced with one (1) new pump tank integral to the new interpass tower/pump tank.
16. Acid Storage Tanks:	The two (2) existing sulfuric acid storage tanks will be retained and repaired.
17. Plant Stack/ Water System:	The stack will be retained and rehabilitated. The associated soft water system will be comprised of new softeners of similar capacity and design.
18. Pumps:	New pumps will be installed as follows: sulfur pumps (3), common acid circulating pump (1), acid drain pump (1), product acid booster pump (1), cooling water pumps (2), and condensate transfer pump (1).
19. Ducts:	Sixteen (16) ducts will be replaced. Four (4) new ducts of the same design will be moved to relocated towers. One duct will be of different metallurgy. One duct will be lenghtened and inlet bird screen replaced. All other ducts will be unchanged from original design.
20. Misc. Piping/Valves:	New piping and valves of similar design and size will be moved to relocated acid towers and coolers.
21. SO2 Monitor:	The existing monitor will be repaired with new retrofit solid state

parts.

22. Office: A generator and air compressor will be removed and a new office will be constructed from the existing room.

23. Civil, Structural, Insulation, Electrical, Painting: New piling and foundations will be supplied for the new drying and certain support equipment. An existing foundation will be used for the new interpass tower/pump tank. Otherwise existing foundations will be utilized for the balance of the plant. Most existing structural steel will be retained and rehabilitated; certain steel will be replaced where needed. Most insulation will be removed and replaced with new insulation. A new motor control center (MCC) will be installed adjacent to existing MCC in the same building; new lighting will be provided; new electrical tray, conduit and cable will be provided for new power, control and instrumentation wiring. All new equipment, vessels, steel, piping and ductwork, as well as existing support and access steel, will be painted.

24. Instrumentation: A new electronic system (distributive control-solid state) will replace the existing pneumatic system.

PROPOSED REPAIRS AND EQUIPMENT REPLACEMENT OF ITEMS ASSOCIATED WITH THE EXISTING SULFURIC ACID PLANT AT PINEY POINT

1. Auxiliary Boiler: A new package boiler rated at 190 MMBtu/hour will replace the existing 96 MMBtu/hour boiler. Note that PPPI is already permitted for the larger boiler (Permit No. AC41-232096).

2. Sulfur Tank and Pit: A new tank of the same size and similar design will replace the existing tank that will be demolished; The existing sulfur pit will be retained and repaired with similar designed coils and cover. Note that the sulfur storage tank is covered under Permit No. AO41-206854.

EXHIBIT II

CERTIFICATION OF COST OF PROPOSED REPAIRS AND EQUIPMENT REPLACEMENT TO THE EXISTING SULFURIC ACID PLANT AT PINEY POINT

The undersigned, being a duly registered professional engineer in the State of Florida, hereby certify that I am experienced in the design, construction and operation and maintenance of sulfuric acid plants. In my professional opinion, the repairs and equipment replacements to the existing sulfuric acid plant at Piney Point, estimated to cost approximately $16.9 million, will not exceed 50% of the cost of building a new grassroots plant of the same capacity (2,000 TPD), design (double contact wet process) and emission limitations (currently permitted limits) on the current Piney Point site. Based on my professional opinion, and the review of independent contractor proposals, the construction of a new grassroots plant having the preceeding specifications will cost in excess of $40 million.

The cost of the repairs and replacement equipment ancillary to the sulfuric acid plant (auxiliary boiler and sulfur tank/pit) are estimated to cost about $1.3 million.

Signed

Gerald W. Hartman
December 13, 1996

Registered Professional Engineer in the State of Florida
License No. PE 48452

Department of Environmental Protection

Lawton Chiles
Governor

Southwest District
3804 Coconut Palm Drive
Tampa, Florida 33619

Virginia B. Wetherell
Secretary

December 19, 1996

Mr. Ivan Nance
Mulberry Phosphates, Inc.
P.O. Drawer 797
Mulberry, FL 33860

RE: Permitting of Piney Point Sulfuric Acid Plant
Repairs/Renovations

Dear Mr. Nance:

From our meeting of December 10, 1996, it appears that the proposed repairs/renovations will not involve air permitting, with the following possible exceptions:

1) Any significant new emission unit, or a change involving a modification (as defined in the air rules) would require a construction permit (which includes public notice). A new molten sulfur tank could fall in this category.

2) The only construction permit applicable to this facility is AC41-2042B, dated 9/1/75, expired 9/1/76. This permit is referenced in our files but we do not have a copy. If there are specific limits/specifications in that permit which the proposed project would revise, that would probably require a construction permit. By this letter, I'm requesting that you and Manatee County check as to whether you have a copy of that permit.

If you have any questions, please call me at (813) 744-6100, Extension 107.

Sincerely,

Gerald Kissel, P.E.
District Air Engineer

cc: Manatee County

c:\piny1296

EXHIBIT
3

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

REGION 4

345 COURTLAND STREET, N.E.
ATLANTA, GEORGIA 30365

AUG 20 1996

4APT-AEB

Mr. David S. Dee
Landers and Parsons
310 West College Avenue
P.O. Box 271
Tallahassee, Florida 32303

SUBJ: McKay Bay Refuse to Energy Facility

Dear Mr. Dee:

This letter is in response to your correspondence to the U.S. Environmental Protection Agency (EPA), dated April 2, 1996, requesting an applicability determination for the above referenced facility. Your correspondence requested an applicability determination pursuant to 40 C.F.R. §60.5 with regard to the retrofitting of equipment at the existing McKay Bay Refuse to Energy facility located in Tampa, Florida.

This determination is primarily based on the federal rule for municipal waste combustors (MWC's), promulgated on December 19, 1995, in the Federal Register under 40 C.F.R. Part 60, Subparts Cb (Emission Guidelines and Compliance Schedules for MWC's) and Eb (Standards of Performance for MWC's for Which Construction is Commenced After September 20, 1994). The rule contains the emission guidelines (EG) for existing MWC sources and the new source performance standards (NSPS) for new MWC sources. In addition to our review and interpretation of these federal regulations with regard to the proposed retrofit at the McKay Bay facility, to ensure national consistency, EPA Region 4 consulted with the Office of Enforcement and Compliance Assurance (OECA) and the Office of General Counsel (OGC), and received technical assistance from the EPA Office of Air Quality Planning and Standards (OAQPS).

Background: Reference Definitions and Concepts

The resultant applicability determination is derived directly from specific portions of the federal rule for MWC's. As a reference, the MWC applicability and the "MWC unit," "Modification," and "Reconstruction" definitions from the federal rule are included in this section.

Under 40 C.F.R. §60.51b, the boundaries of a municipal solid waste combustor are defined as follows:

EXHIBIT
C

The MWC unit includes, but is not limited to the municipal solid waste fuel feed system, grate system, flue gas system, bottom ash system, and the combustor water system. The MWC boundary starts at the municipal solid waste pit or hopper and.extends through:

(i) the combustor flue gas system, which ends immediately following the heat recovery equipment, or if there is no heat recovery equipment, immediately following the combustion chamber

(ii) the combustor bottom ash system, which ends at the truck loading station or similar ash handling equipment that transfer the ash to final disposal, including all ash handling systems that are connected to the bottom ash handling system

(iii) the combustor water system, which starts at the feed water pump and ends at the piping exiting the steam drum or superheater

The MWC unit does not include air pollution control equipment, the stack, water treatment equipment, or the turbine-generator set.

Under 40 C.F.R. §60.51b, Modification (or Modified MWC Unit) and Reconstruction are defined as follows:

Modification or Modified MWC Unit means a MWC unit to which changes have been made after June 19, 1996, if the cumulative cost of the changes, over the life of the unit, exceed 50 percent of the original cost of construction and installation of the unit (not including the cost of any land purchased in connection with such construction or installation) updated to current costs; or any physical change in the MWC unit or change in the method of operation of the MWC unit [that] increases the amount of any air pollutant emitted by the unit for which standards have been established under section 129 or section 111. Increases in the amount of any air pollutant emitted by the MWC unit are determined at 100 percent physical load capability and downstream of all air pollution control devices, with no consideration given for load restrictions based on permits or other nonphysical operational restrictions.

Reconstruction means rebuilding a MWC unit for which the reconstruction commenced after June 19, 1996, and the cumulative costs of the construction over the life of the unit exceed 50 percent of the original cost of construction and installation of the unit (not including any cost of land purchased in connection with such construction or installation) updated to current costs (current dollars).

Under 40 C.F.R. §60.50b, the applicability of the MWC guidelines and standards are outlined, to exclude certain actions:

(d) Physical or operational changes made to an existing MWC unit primarily for the purpose of complying with emission guidelines under subpart Cb are not considered a modification or reconstruction and do not result in an existing MWC unit becoming subject to this subpart.

As the definitions state, the determination of the occurrence of a modification/reconstruction at a MWC unit is based on a cost analysis process. This process includes four steps:

(1) Determine the original construction and installation costs for the unit.

(2) Aggregate all costs of changes to the unit since start-up, including all costs for the emission guidelines.

(3) Subtract the "allowed" retrofit costs required for compliance with the emission guidelines.

(4) Compare the cost of changes to the unit since start-up to the original cost of the unit. If this value is greater than 50 percent of the original cost then a modification/reconstruction has occurred.

Your correspondence addresses the "allowed" retrofit costs (in step 3), but does not address the other costs (in item 2) for McKay Bay. This response will address all aspects of the cost analysis process.

<u>1985 Conversion to Waste-to-Energy Facility</u>

The McKay Bay Refuse-to-Energy Facility was originally constructed in 1967 as a solid waste combustor without heat recovery. The original facility included three combustion units, each with a capacity of 250 tons per day of municipal solid waste. This facility was in operation from 1967 until it ceased operation in 1979. In 1985, the facility began operations after being converted to a waste-to-energy facility. This conversion included the replacement of three Volund rotary kiln combustion units and the installation of one new Volund kiln unit (250 tons per day capacity) at the facility. A waste heat recovery system, a turbine generator, and four electrostatic precipitators were also installed during the conversion. Under the federal MWC rule, the cumulative costs of the changes at McKay Bay are included in determining the occurrence of a modification/reconstruction. The original three combustion units began operation in 1967; the fourth unit began operation in 1985. In order to complete the applicability determination of the subpart Cb emission guidelines or subpart Eb performance standards under the "cumulative cost" criteria, we are requesting the submittal of information outlining the waste-to-energy conversion costs and other modification costs for each combustion unit from the initial start-up dates of 1967 (for units 1, 2, and 3) and 1985 (for unit 4) through June 18, 1996.

Applicability Determination: Source Retrofit Categories

This section will initially outline our applicability determination, formulated in response to your question concerning whether the proposed retrofit improvements at McKay Bay would constitute modification/reconstruction of the MWC unit under the EG. Under the potential retrofit improvements discussed in your correspondence, categories for these improvements have been developed. These categories are:

(1) Improvements to components that are not part of the definition of a MWC unit, are being undertaken to comply with the EG, and are not considered part of potential costs of modification/reconstruction. This category has been determined to include the following potential improvements:

- Air Pollution Control Equipment
- Continuous Emissions Monitors
- Induced Draft Fans
- Electrical System (portions)
- Combustion Control Systems (portions)

(2) Improvements to components that are part of the definition of a MWC unit, are being undertaken to comply with the EG, and are not considered part of potential costs of modification/reconstruction. This category has been determined to include the following potential improvements:

- Auxiliary Burners
- Furnace, Grates, and Kilns
- Boiler and Economizer
- Ash Enclosures
- Ash Conveyor System

(3) Improvements to components that are not part of the definition of a MWC unit, are not being undertaken to comply with the EG, and are not considered part of potential costs of modification/reconstruction. This category has been determined to include the following potential improvements:

- General Equipment and Maintenance Building
- Control Room Systems

- Ash Building
- Ash Treatment System
- Tipping Floor

(4) Improvements to components that are part of the definition of a MWC unit, are not being undertaken to comply with the EG, and are considered part of potential costs of modification/reconstruction. This category has been determined to include the following potential changes and improvements:

- Furnace Configuration
- Refuse Pit
- Cranes

Within these four categories, for the purposes of determining whether or not this facility meets the criteria for modification/reconstruction under 40 C.F.R. §60.51b, the potential source improvements identified in Category 4 only would be considered a part of the potential costs of modification/reconstruction at the McKay Bay facility. In addition, the cumulative costs of changes over the life of the unit from the initial construction date through June 18, 1996, would be included in the potential costs of modification/reconstruction at the McKay Bay facility. A summary of the potential source improvements and their applicability criteria within this determination for the McKay Bay facility is presented in Table 1.

Applicability Determination: Discussion

Different interpretations are apparent when comparing our determination and the proposed determination in your correspondence. The basis for EPA's determination regarding the potential source improvements at the McKay Bay facility will be discussed in this section.

Category 1 Improvements: Air pollution control equipment is specifically excluded from the MWC unit definition and is being installed for compliance with the EG. Continuous emissions monitors are being installed specifically for compliance with the EG. As the rule (at §60.51b) is written, induced draft fans are not part of the MWC unit definition. This exclusion does not set a precedent however, for applicability to other NSPS boundary determinations. This exclusion is only for sources affected under subparts Cb, Ea, and Eb. The portions of the electrical system that are being installed for compliance with the EG (for compatibility with the new air pollution control system) are excluded from consideration as a modification/reconstruction. No costs associated with these potential improvements are included in modification/reconstruction cost calculations. In addition, control systems for the combustion units and the air pollution control equipment are not included in the MWC unit definition, thus their costs can be excluded.

Category 2 Improvements: Auxiliary burners are included in the MWC unit definition and are being installed for compliance with the EG for the maintenance of good combustion practices. The furnaces, grates, and kilns are included in the MWC unit definition and are being installed primarily for compliance with the EG to meet the new emission limits. The boiler and economizer are included in the MWC unit definition and are being installed for compliance with the EG to maintain compatibility with the furnace system upgrades. The ash enclosures are included in the MWC unit definition and are being installed for compliance with the EG for the control of fugitive ash emissions. The ash conveyor system is included in the MWC unit definition and is being installed for compliance with the EG for the control of fugitive ash emissions. No costs associated with these potential improvements are included in modification/reconstruction cost calculations.

Category 3 Improvements: General equipment improvements and the maintenance building are excluded from the MWC unit definition and are not being installed or improved for compliance with the EG. The control room systems are excluded from the MWC unit definition and are not being installed for compliance with the EG. The ash building is excluded from the MWC unit definition, is not being installed primarily for compliance with the EG, and is not primarily for the control of fugitive ash emissions (fugitive ash emissions are controlled by the ash conveyor system enclosures). The ash treatment system will be installed in the ash building and will treat fly ash prior to its combination with bottom ash, dewatering, and disposal. The ash treatment system, however, does not constitute a part of the ash handling system. The ash treatment system is excluded from the MWC unit definition and is not being installed primarily for compliance with the EG. The tipping floor is specifically excluded from the MWC unit definition and is not being improved for compliance with the EG. No costs associated with these potential improvements are included in modification/reconstruction cost calculations.

Category 4 Improvements: The furnaces are specifically included in the MWC unit definition, however, a change in the existing furnace configuration would not be completed primarily for compliance with the EG.[1] Furnace configuration changes, such

---

1 The McKay Bay facility is currently configured with four combustion units, each with a capacity of 250 tons per day.

as a change to either three units each with 333 tons per day capacity or two units each with 500 tons per day capacity, are a fundamental change to the MWC units at McKay Bay. These furnace configuration changes require a "unit by unit" comparison of costs to an existing 250 tons per day capacity unit at McKay Bay. Therefore, all costs associated with this potential change are included in modification/reconstruction cost calculations.

The intent of the rule was to include the refuse pit or the hopper, whichever occurs first, specifically in the MWC unit definition. Improvements to the refuse pit would not be done primarily for compliance with the EG. Therefore, all costs associated with this potential improvement are included in modification/reconstruction cost calculations.

Cranes are specifically included in the MWC unit definition as part of the fuel feed system. Any improvements to the cranes would not be done for compliance with the EG. All costs associated with this potential improvement are included in modification/reconstruction cost calculations.

Applicability Determination: Modification/Reconstruction Costs

On the basis of the definitions of modification and reconstruction in 40 C.F.R. §60.51b and our analysis of the proposed retrofit at the McKay Bay facility, the following improvements have been determined to be considered in the modification/reconstruction cost analysis: Furnace Configuration Change, Refuse Pit, Cranes. This cost comparison is to be completed on a "unit by unit" basis, comparing each existing unit's original cost of construction and installation (not including any cost of land purchased in connection with such construction or installation) updated to current costs (current dollars) to the replacement or modified unit's cumulative costs of changes over the life of the unit. These cumulative costs of changes over the life of the unit are not to exceed the threshold level of 50 percent of the original unit's updated current cost for a source to remain subject to the EG.

In response to your queries regarding original unit costs, new facility costs, and current dollars computations, EPA has the following responses:

(1) There are two separate original costs for the MWC units at McKay Bay. The cost of the three original combustion units may be determined from the comparison of originally issued bonds for the construction of the facility, as originally constructed in 1967 as a solid waste combustor. For the fourth combustion unit, constructed new in 1985, its original cost is determined from this baseline date (1985). For the McKay Bay facility, however, a better comparison

cost may be determined from an accurate estimate of the cost of a new MWC facility of comparable design.

(2) To determine the fixed capital cost required to construct a comparable entirely new MWC facility, reference the EG proposal from September 20, 1994, of the Federal Register. On page 48240, Tables 3A and 3B outline the Capital and Annualized Costs of Air Pollution Control For Typical New and Existing Large and Small MWC Plants.

(3) The method for performing a cost update to current dollars can be selected by the source. Provided the appropriate historical and financial documentation is included, the ENR Construction Price Index can be used.

We look forward to your submittal of additional data to complete the subpart Cb/Eb applicability determination. If you have any questions or comments concerning this response, please contact either Mr. Brian Beals or Mr. Scott Davis of my staff at (404) 347-3555, extensions 4167 or 4144, respectively.

Sincerely,

Winston A. Smith
Director
Air, Pesticides and Toxics
Management Division

Enclosure

cc: Joyce Chandler, OECA
Leslye Fraser, OGC
Walt Stevenson, OAQPS
Clair Fancy, Florida DEP
Iwan Choronenko, Hillsborough County EPC
Jerry Campbell, Hillsborough County EPC

TABLE 1

Potential Source Improvement	Defined under "MWC Unit"?	For EG Compliance?	Include in Reconstruction?
Air Pollution Control Equipment	NO	YES	NO
Continuous Emissions Monitors	NO	YES	NO
Auxiliary Burners	YES	YES	NO
Induced Draft Fans	NO	YES	NO
General Equipment and Maintenance Building	NO	NO	NO
Furnaces, Grates, and Kilns	YES	YES	YES
Furnace Configuration	YES	NO *	YES *
Boiler and Economizer	YES	YES	NO
Electrical System	NO *	YES	NO
Control Room Systems	NO *	NO *	NO
Control Systems (APC/Combustor)	NO *	YES	NO
Ash Building	NO	NO *	NO
Ash Enclosures	YES *	YES	NO
Ash Conveyor System	YES	YES	NO
Ash Treatment System	NO	NO	NO
Tipping Floor	NO	NO	NO
Refuse Pit	YES *	NO	YES *
Cranes	YES *	NO	YES *

* Differences exist between Determinations by EPA and the Source

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
Office of Air Quality Planning and Standards
Research Triangle Park, North Carolina 27711

AUG 11 1992

MEMORANDUM

SUBJECT: Proposed Netting for Modifications at Cyprus Northshore Mining Corporation, Silver Bay, Minnesota

FROM: John Calcagni, Director
Air Quality Management Division (MD-15)

TO: David Kee, Director
Air and Radiation Division, Region V (5A-26)

This memorandum responds to your July 2, 1992 inquiry regarding the applicability of the prevention of significant deterioration (PSD) program to proposed construction at a taconite ore processing facility owned and operated by Cyprus Northshore Mining Corporation (Cyprus) in Silver Bay, Minnesota. Cyprus proposes to modify its existing source by installing two new rotary hearth furnaces at the facility. To prevent this physical change from resulting in an increase in emissions and thus subjecting the source to PSD as a "major modification," Cyprus seeks to take credit for the shutdown of several, existing straight-grate furnaces which would be replaced as part of the proposed work. Since these furnaces have not operated since 1982, you have asked whether Cyprus may use the 1981 and 1982 actual emissions of these furnaces to establish the netting credit. Subsequent to your memorandum, counsel for Cyprus has written Region V urging the Environmental Protection Agency's (EPA's) approval of a baseline using actual emissions from these furnaces during the period of July 1975 to June 1977. However, after reviewing both the facts as presented to me, as well as the appropriate regulations and statutory provisions, it does not appear that either suggested baseline is appropriate. Indeed, for the reasons set forth in this memorandum, it does not appear that Cyprus can be credited with any emissions reductions stemming from the removal of the existing furnaces at the West Plant.

EXHIBIT D

FACTUAL BACKGROUND[1]

The taconite ore processing facility at issue is a single major stationary source consisting of an East Plant and a West Plant. Reserve Mining (Reserve)--the owner before Cyprus--originally produced oxidized iron ore pellets from both plants. According to Cyprus, which took over the plant in 1989, Reserve operated the plant at near capacity until the mid-1970's when production began to decline due to an economic downturn in the domestic steel industry, labor unrest, and the installation of pollution control equipment. Finally, in 1982, Reserve shut down the West Plant operations due to poor market conditions. Reserve continued to manufacture pellets in the East Plant and maintained the equipment in the West Plant through 1986. At that point the company went bankrupt.[2]

Cyprus purchased the facility in 1989 and resumed operations in the East Plant in 1990. The West Plant operations were never resumed. Indeed, in 1989, the Minnesota Pollution Control Agency issued an air permit to Cyprus that apparently prohibited operation of four of the six furnaces at the West Plant.

Cyprus now proposes to restart manufacturing at the West Plant. To this end, the company wants to install two new rotary hearth furnaces as part of a switch to a direct reduction pellet process. [Cyprus currently has an option for the direct reduction technology which must be exercised before the end of this year.] The new West Plant furnaces will have significant nitrogen oxides (NO_x) and sulfur dioxide (SO_2) emissions. According to Region V and Cyprus, the potential-to-emit for the two new furnaces standing alone greatly exceeds the 40 tons-per-year (tpy) significance level applicable to both SO_2 and NO_x [see 40 CFR 52.21(b)(23)(i)]. Cyprus proposes to avoid PSD review by netting the emissions from the two new rotary hearth furnaces against the emissions associated with the shutdown of three of the existing furnaces that will be removed from the West Plant as part of the proposed renovation.

---

[1] This statement of the facts is based on your memorandum to me dated July 2, 1992 and the July 27, 1992 letter Region V received from Denise W. Kennedy and Robert T. Connery, counsel for Cyprus. The Office of Air Quality Planning and Standards has made no independent effort to verify this factual information.

[2] Prior to the bankruptcy, the union representing the workers at the West Plant filed a grievance against Reserve seeking severance pay on the grounds that the West Plant had been permanently shut down. However, in February 1986, the Iron Ore Industry Board of Arbitration ruled that Reserve did not at that time intend to permanently shut down the West Plant.

STATUTORY AND REGULATORY BACKGROUND

The PSD program [Clean Air Act (CAA), sections 160-169] applies in attainment areas [i.e., those areas which have attained the national ambient air quality standards (NAAQS)]. The new source review (NSR) requirements apply to newly-constructed sources and to "major modifications," physical or operational changes occurring at existing sources that result in significant net emissions increases. The PSD definition of modification contemplates a two-step test for determining whether activities at an existing facility constitute a major modification subject to review. In the first step, the reviewing authority determines whether a physical or operation change will occur. If so, the reviewing authority proceeds to determine whether a physical or operational change will result in an emissions increase over baseline levels. Routine changes and certain other changes are excluded by regulation from the definiton of physical or operational change (see 57 FR 32314, 32316). In this second step, EPA regulations focus on whether the proposed change will result in a "significant net emissions increase of any pollutant subject to regulation under the CAA" [see 40 CFR 52.21(b)(2)(i)]. A "net emissions increase" is defined as the increase in "actual emissions" from the particular physical or operational change, together with any other "contemporaneous" increases or decreases in actual emissions [see 40 CFR 52.21(b)(3)(i)]. To be "contemporaneous," the emissions increases or decreases must have "occurred" within the 5 years preceding the proposed change [see 40 CFR 52.21(b)(3)(ii)].

Applicability of the PSD provisions must be determined in advance of construction and on a pollutant-by-pollutant basis. Specifically, to determine whether a proposed change at an existing source will result in an increase in actual emissions, the source must first determine a baseline level of actual emissions. The applicable regulation defines actual emissions on a particular date as "average rate, in tpy, at which the unit actually emitted the pollutant during a 2-year period which precedes the particular date and which is representative of normal source operation" [see 40 CFR 52.21(b)(21)(ii)]. The Administrator shall allow use of a different time period "upon a determination that it is more representative of normal source operation." [Ibid.] The EPA has "typically used the 2 years immediately preceding the physical or operational change to establish the baseline" (see 57 FR 32317).

Because the applicability determination must be made in advance of construction, EPA's PSD regulations provide that when an emissions unit "has not begun normal source operations," actual emissions equal the "potential-to-emit" of the unit [see 40 CFR 52.21(b)(21)(iv)]. In other words, to determine if there is an emissions increase, the regulations require EPA to compare the source's actual emissions before the change and its potential emissions after the change. This is the so-called "actual-to-potential" test. This test, in effect, presumes that following the change the source will operate at 100 percent of its physical capacity. The source owner may overcome this presumption by agreeing to federally-enforceable restrictions that would prevent the plant from significantly exceeding its pre-modification emissions baseline.[3]

The determination of whether the physical or operational change would result in an increase in actual emissions is but one factor in determining whether the change will increase emissions. As mentioned, if the change will, standing alone, result in an increase in emissions, the source must next identify and quantify any other prior increases and decreases in "actual emissions" that are "contemporaneous" with the particular change and which are otherwise creditable [see 40 CFR 52.21(b)(3)(i) and (b)(21)]. Reductions are not creditable if the Administrator "has relied on it in issuing a permit" and that permit remains in effect at the time of the proposed change [see Id. at 52.21(b)(3)(iii)]. Also, reductions must have "approximately the same qualitative significance for public health and welfare as that attributed to the increase from the particular change" [see Id. at 52.21(b)(3)(vi)(c)].

It should be noted that the initial inquiry as to whether the change, standing alone, will result in an increase in actual emissions is calculated by determining the emissions increase at the particular emissions units to be changed or added [see

---

[3] In Puerto Rican Cement Co. v. EPA, 889 F.2d 292 (1st Cir. 1989), the court of appeals upheld EPA's application of the actual-to-potential test in a case involving modernization of cement kilns. However, in Wisconsin Elec. Power Co. (WEPCO) v. Reilly, 893 F.2d 901 (7th Cir. 1990), a different appeals court struck down EPA's actual-to-potential test as it applied to "like-kind" modifications at utilities. In a subsequent rulemaking, EPA adopted an "actual-to-future-actual" test for utility modifications to existing sources. Under that test, EPA compares the pre-change actual emissions baseline to a projection of future emissions that is based on the unit's past operating history and other factors (see 57 FR 32314). Even ignoring the fact that this rule is limited to electric steam generating units, the actual-to-future-actual test would be inapplicable here since Cyprus is essentially proposing to add a new furnace rather than merely making changes to the existing furnaces at the West Plant. Because it is impossible to reliably project future levels of capacity utilization and, hence, actual emissions at a new unit that has no past operating history, EPA's recent rulemaking retains the actual-to-potential test when the change at issue is the addition of a new emissions unit (see id., at 32323).

40 CFR 52.21(b)(21); NSR Workshop Manual, p. A.46 (Draft October 1990)]. The subsequent netting calculation includes all increases and decreases--anywhere at the source--that are contemporaneous and creditable [see 40 CFR 52.21(b)(3)(i); Workshop Manual at A.46-47].

DISCUSSION

A. General Applicability of PSD

As discussed, the first question is whether the work proposed constitutes a physical or operational change. This must be answered in the affirmative. The source proposes to add two new rotary furnaces and make all necessary changes to the West Plant to operate these new additions. This is not a case where the source is reactivating a shut-down facility and making only "routine" changes to bring it back on line. For this reason, there is no dispute that this new construction constitutes a physical change.

The second step is to determine whether this physical change will result in an increase in actual emissions at the emissions units affected. Here again, the answer is <u>yes</u>. Based on the description of the project we have, it appears that the work at issue is the installation of a direct reduction pellet process, including two new emissions units--two new rotary hearth furnaces.[4] Since these emissions units are new, their baseline level of actual emissions is zero. As discussed, their potential emissions are over the significance levels, so the proposed work will trigger PSD, unless there are contemporaneous increases and decreases at the source that can be used to net out of review.

B. Using the Shutdown of the West Plant as a Contemporaneous Decrease

Since the project, standing alone, will result in a significant increase in emissions, Cyprus must identify sufficient contemporaneous decreases to avoid PSD. The company urges EPA to credit the reductions associated with the removal of several existing furnaces at the West Plant. However, as discussed below, these reductions are neither contemporaneous nor otherwise creditable. Moreover, even if these reductions were eligible to be considered for netting, they would have no value since the baseline for the West Plant furnaces is zero.

---

[4] Cyprus does not contest that the work at issue involves the installation of new units rather than the rehabilitation of the existing emissions units.

1. Netting Reductions Cannot "Occur" Outside the Contemporaneous Period

The EPA's regulations limit netting to those emissions reductions that occur within the 5-year period that precedes the proposed change:

> An increase or decrease in actual emissions is contemporaneous with the increase from the particular change only if it <u>occurs</u> between: a) The date 5 years before construction on the particular change commences; and b) the date that the increase from the particular change occurs.

[see 40 CFR 52.21(b)(3)(ii)(emphasis added)]. Thus, if the reduction occurred more than 5 years before the commencement of construction of the proposed change, it is not contemporaneous. Here, the reduction undeniably took place in 1982 when the emissions from the West Plant fell to zero. This is outside the 5-year window. However, Cyprus contends that a reduction does not occur "until such time as the source determines not to resume operation of the equipment in question, or the source is, in some other way, precluded from operation of the equipment." In other words, a credible reduction does not "occur" when emissions decrease. It occurs when the source elects to take credit for it.

In <u>Alabama Power Co. v. Costle</u>, 636 F.2d 323, (D.C. Cir. 1979), the court recognized that EPA has substantial discretion in applying the plantwide bubble concept so as to reconcile the statutory goals of preserving clean air and providing for economic growth [see Id. at 400-03]. In particular, the court noted that EPA should enable emissions increases from the addition of a new unit to be set off by decreases resulting from the abandonment of an old unit [Id. at 401]. However, the court also emphasized that offset reductions claimed by industry to net out of review must be "<u>substantially</u> contemporaneous" (Id. at 402) (emphasis added). The EPA's regulations implemented this standard by setting 5 years, plus time for construction, as the period of contemporaneity. The EPA selected 5 years (despite proposing a 3-year period) on the basis that 5 years would be long enough to accommodate "corporate expansion planning" and would "minimize any incentive for keeping old or obsolete equipment in operation beyond its usefulness" (see 45 FR 52701). On the other hand, EPA declined to expand the contemporaneous period to any prior reduction that had occurred at the plant:

> [Industry commenters] urged EPA to treat <u>any</u> emissions decrease which occurs before a proposed increase as being "contemporaneous" with that increase. The EPA, however, has rejected those urgings. To credit any

> decrease that occurs before a proposed increase would violate any common sense notion of what is "contemporaneous," since a period of contemporaneity must have some definite boundaries.

[Ibid. (emphasis in original)]. Cyprus' interpretation of this provision violates this common sense understanding of a limited contemporaneous period. Under Cyprus' interpretation, sources could bring in any prior reduction, no matter how old or obscure, so long as the source retained the legal right to return to that emissions level.

Cyprus' proposed interpretation of EPA's regulations conflicts with the plain meaning of the contemporaneity requirement. Moreover, allowing credit for very old emissions reductions undermines the purpose of the contemporaneity requirement by enabling new construction activity to burden the environment with levels of air pollution higher than they have been for many years. The EPA has already given sources a generous 5-year window to aggregate any decreases to net out of review. Since the reduction in actual emissions at the West Plant occurred before the 5-year period, it cannot be used to net out of review.

2. The Baseline for the West Plant Furnaces

Even if the reductions at the West Plant could be deemed to have occurred in 1989, Cyprus still must establish the value of the reductions. In general, this requires a comparison of the emissions levels before and after the reduction. The problem for Cyprus is, of course, the baseline for the West Plant reductions. The EPA policy presumes a calculation based on the 2 years that immediately preceded the change [see 45 FR 52676, 52705, 52718 (1980)]. If EPA uses the 1989 date as the point when the reduction occurred, since the units did not operate during that period, the presumptive baseline is zero and there is no credible reduction. To avoid this result, Cyprus seeks to use a time period well outside the contemporaneous period (July 1975 to June 1977).

As discussed, the Administrator's power to use a different baseline period is limited to those circumstances where the source demonstrates that some time period other than the 2 years that precede the change is more representative of normal source operation. In general, EPA has indicated that this provision is to apply to catastrophic occurrences such as strikes and major industrial accidents (see NSR Workshop Manual, p. A.39). For example, in the WEPCO applicability determination, EPA found the fourth and fifth years prior to the proposed renovation project more representative, since the utility's capacity was greatly reduced after that period due to a cracked steam drum and other severe physical problems (see 57 FR 32323).

On the other hand, EPA has declined to consider a stop in operations, in and of itself, to constitute grounds to change the baseline years. For instance, in the WEPCO rulemaking, EPA adopted a presumption for utilities that considers any 2 years within the 5 years that precede the change to be representative of normal source operations. However, EPA rejected comments seeking to allow further accommodations for units that had been out of operation (see 57 FR 32325):

> The EPA disagrees with comments seeking to allow the use of any 2 consecutive years within the last 5 years of a unit's "operation" rather than within the 5 years directly preceding the proposed change. A shifting of the 5-year period would be difficult to harmonize with definitions of contemporaneous contained in the regulations. This type of open-ended provision would even credit a unit which has been inoperative for 20 or 30 years or longer with a high level of emissions.

Based on these policies, EPA cannot approve either a 1981-1982 baseline or the earlier period put forward by Cyprus. Cyprus has not demonstrated that catastrophic occurrences or other extraordinary circumstances disrupted the West Plant for the entire period between the proposed change and the years Cyprus claims are representative of "normal source operations." Indeed, it is admitted that in the last 10 years the source has been idle due to general economic conditions, and the zero baseline appropriately reflects source utilization under these longstanding market conditions. On the other hand, the very fact that Cyprus seeks to throw out the most recent 13 years suggests that the years Cyprus puts forward are not representative of normal operations in any realistic sense. For these reasons, the baseline for the West Plant furnaces should be zero.

3. Health and Welfare Effects of the Proposed Netting

The PSD regulations restrict the creditability of some decreases in emissions for the purpose of emissions netting. In particular, one provision allows credit for a reduction only to the extent that it has approximately the same qualitative significance for public health and welfare as the increase from the proposed change [see 52.21(b)(3)(vi)(c)]. Where there is reason to believe that the reduction in ambient concentrations from the decrease will not be sufficient to prevent the proposed emissions increase from causing or contributing to a violation of any NAAQS or PSD increment, this provision requires an applicant to demonstrate that the proposed netting transaction (despite the absence of a significant net increase in emissions) will not cause or contribute to such a violation (see 54 FR 27298). Even if EPA found the proffered reductions otherwise quantitatively acceptable in this case--where the existing emissions units have not contributed to ambient concentrations for the last 10 years--Cyprus would have to perform sufficient air quality modeling to demonstrate that the emissions increase from the new units would not violate the applicable NAAQS and PSD increments before the reductions could be credited (see 54 FR 27298).

CONCLUSION

In conclusion, based on the information submitted to date, the proposed 1975 to 1977 baseline period is unacceptable. We are, however, acutely aware of Cyprus' need and concern that their project proceed in a timely manner. To this end, we are willing to work with the Region, the State, and Cyprus to facilitate the resolution of any outstanding permit issues and to assist in the expedited processing of a PSD permit.

LANDERS & PARSONS, P.A.
ATTORNEYS AT LAW

Copy to Claire F.
Al Linero
return this copy
Howard 3/5

CINDY L. BARTIN
DAVID S. DEE
JOSEPH W. LANDERS, JR.
JOHN T. LAVIA, III
FRED A. McCORMACK
PHILIP S. PARSONS
ROBERT SCHEFFEL WRIGHT

HOWELL L. FERGUSON
OF COUNSEL

VICTORIA J. TSCHINKEL
SENIOR CONSULTANT
(NOT A MEMBER OF THE FLORIDA BAR)

310 WEST COLLEGE AVENUE
POST OFFICE BOX 271
TALLAHASSEE, FLORIDA 32302
TELEPHONE (904) 681-0311
TELECOPY (904) 224-5595

RECEIVED
MAR 5 1997
BUREAU OF
AIR REGULATION

RECEIVED
MAR 5 1997
BUREAU OF
AIR REGULATION

March 3, 1997

Mr. Douglas Beason, Esquire
Office of General Counsel
Department of Environmental Protection
2600 Blairstone Road
Twin Towers Office Building
Tallahassee, FL 32399

RE: Piney Point Phosphates, Inc. (PSD-FL-144)

Dear Mr. Beason:

As you know, this law firm is assisting Manatee County ("County") with its evaluation of a proposal by Piney Point Phosphates, Inc. ("Piney Point"), to rebuild and restart its existing sulfuric acid plant in Manatee County. Manatee County's concerns about Piney Point's project were described in detail in our letter dated January 16, 1997 to you.

We would like to thank you and the Department of Environmental Protection ("DEP") for promptly responding to the County's concerns about Piney Point. We also want to thank you, DEP and Piney Point for allowing us to attend DEP's meeting with Piney Point on February 24, 1997. The meeting was informative and constructive. We hope that the meeting and subsequent discussions between the parties will enable the Department to resolve Manatee County's concerns without litigation or other adversarial proceedings.

We have advised the County's staff and consultants about the factual and legal contentions that were presented by Piney Point on February 24th. We have asked the County's staff and consultants to provide us with their comments about Piney Point's contentions, which we will submit to DEP and Piney Point as expeditiously as possible (i.e., within the next 7 to 10 days).

Manatee County intends to work with DEP and Piney Point in good faith to resolve the environmental law issues that have been raised by Piney Point's proposal; however, the County also intends to preserve its legal rights and remedies in the event that the County's concerns cannot be resolved amiably. The County wants to ensure that DEP makes a timely decision about the relevant environmental law issues. A timely decision is important in this case because Piney Point intends to commence construction in the near future. Under state and federal law, the environmental law issues in this case must be resolved <u>before</u> the commencement of construction. Further, during the meeting on February 24th, Piney Point's representatives repeatedly stated that Piney Point would litigate if DEP concluded that Piney Point must comply with DEP's preconstruction review procedures in this case. Given Piney Point's statements, the County wants to be prepared to respond if Piney Point refuses to comply with DEP's decision.

For the reasons set forth above, Manatee County has prepared a verified complaint against DEP and Piney Point, in accordance with Section 403.412(2), Florida Statutes. The complaint is being filed today with the DEP Clerk and a copy is attached for your review. Under Section 403.412(2), the Department has 30 days to take appropriate action on the County's verified complaint. If the Department does not take appropriate action within 30 days, the County will decide whether to file suit in circuit court for injunctive relief.

The County's verified complaint also is intended to serve as the County's petition for enforcement of DEP's rules, pursuant to Section 120.69(1), Florida Statutes. If necessary, the County and one or more of its residents may file a petition for enforcement in circuit court. A copy of the County's verified complaint is being provided to the Attorney General to satisfy the notice requirements in Section 120.69, Florida Statutes.

Please note that the County's verified complaint only summarizes the County's concerns. A more detailed statement of the relevant facts, statutes, and rules is contained in our letter dated January 16, 1997, which is incorporated in the complaint by reference. If it is necessary to file suit in circuit court, we will update the facts in the complaint and we will prepare an appropriate pleading that includes more of the details from our prior letter to you.

Please call me if you have any questions.

Sincerely,

David S. Dee

cc: w/enc.
DEP Secretary Virginia Wetherell
Attorney General Robert Butterworth
Dr. Richard Garrity
Mr. Howard Rhodes
Mr. Paul Amundson
Mr. Hamilton Rice, Jr.

/MAN7

BEFORE THE STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

BOARD OF COUNTY COMMISSIONERS OF MANATEE COUNTY, a political subdivision of the State of Florida,	
Complainant,	
vs.	DEP Case No. 97-
FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION and PINEY POINT PHOSPHATES, INC.,	
Respondents.	

MANATEE COUNTY'S VERIFIED COMPLAINT

Complainant, the Board of County Commissioners of Manatee County ("Manatee County" or "County"), by and through its undersigned attorneys, files this verified complaint with Respondents, the Florida Department of Environmental Protection ("Department" or "DEP") and Piney Point Phosphates, Inc. ("Piney Point"), pursuant to Section 403.412(2), Florida Statutes ("F.S."), and says:

PARTIES

1. Complainant, Manatee County, is a political subdivision of the State of Florida. The County was created pursuant to Article VIII, Section 1 of the Florida Constitution and its boundaries are defined in Section 7.41, F.S.

2. Respondent, DEP, is an agency of the State of Florida. The Department has the statutory authority and duty to enforce the provisions of Chapter 403, F.S., and the rules adopted

thereunder for the protection of the air, water and other natural resources of the State of Florida.

3. Respondent, Piney Point, is a Florida corporation that owns a sulfuric acid plant located in Manatee County. The construction and operation of Piney Point's sulfuric acid plant is subject to the provisions of Chapter 403, F.S., and the DEP rules adopted in Chapter 62, Florida Administrative Code ("F.A.C.").

4. Piney Point owns a fertilizer manufacturing facility ("Facility") that is located in Manatee County. The Facility includes a sulfuric acid plant, a phosphoric acid plant, storage and shipping areas, a phosphogypsum disposal area, an industrial process water recirculation system, and related structures. Piney Point's Facility has not been in operation since 1992.

5. Piney Point intends to rebuild and restart the sulfuric acid plant at the Facility. Piney Point estimates the proposed work on the sulfuric acid plant will cost at least $13 million ($13,000,000) and perhaps as much as $18 million ($18,000,000) to complete. Among other things, Piney Point intends to replace the boiler feedwater heater, the economizer, all three acid towers, all three mist eliminators, a heat exchanger, the condensate storage tank, the cooling tower, the acid coolers, the acid pump tanks, nine pumps, sixteen ducts, and various other components of the sulfuric acid plant.

6. In the past, Piney Point has obtained certain permits from DEP (or DEP's predecessor) for the construction and

operation of Piney Point's sulfuric acid plant. At this time, however, Piney Point intends to commence construction on the sulfuric acid plant without obtaining any additional permits, permit modifications, or other preconstruction approvals from DEP. Piney Point has announced that it will proceed with the construction of the sulfuric acid plant in the near future.

7. DEP has not yet decided whether the proposed work on Piney Point's sulfuric acid plant is subject to any additional permitting requirements under Chapter 403, F.S., or the DEP rules in Chapter 62, F.A.C. Consequently, DEP has not stopped and is not stopping Piney Point from moving forward with its construction project.

8. Manatee County believes that, under the applicable state and federal regulations, Piney Point must obtain DEP's approval before Piney Point commences construction on the sulfuric acid plant. Piney Point's work on the sulfuric acid plant is subject to substantive and procedural DEP requirements that are designed to protect Florida's environment and the interests of its citizens. DEP has a statutory duty under Chapter 403, F.S., to review Piney Point's proposed work on the sulfuric acid plant and to compel Piney Point to comply with the applicable DEP regulations.

9. Manatee County is adversely affected by DEP's failure to appropriately regulate Piney Point's work on the sulfuric acid plant. Piney Point's sulfuric acid plant will emit air pollutants into Manatee County's airshed and will degrade the air

quality in Manatee County. The emissions from Piney Point's sulfuric acid plant will impair, pollute or otherwise injure the natural resources of Manatee County.

10. On January 16, 1996, Manatee County submitted a letter to DEP which contained a detailed discussion of the issues addressed in this complaint. The County's letter is attached hereto and incorporated herein by reference.

COUNT I--RECONSTRUCTION

11. All of the allegations in paragraphs 1-10, above, are adopted and incorporated herein by reference.

12. DEP Rule 62-204.800(7)(d), F.A.C., adopts by reference most of the provisions of 40 Code of Federal Regulations ("CFR") Part 60, Subpart A, including the provisions of 40 CFR 60.15. In pertinent part, 40 CFR 60.15(b) defines the term "reconstruction" to mean the

> replacement of components of an existing facility to such an extent that . . . [t]he fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility . . . .

If an owner proposes the reconstruction of an existing facility, 40 CFR 60.15(d) requires the owner to submit notice to the appropriate agency and then comply with certain review procedures before commencing the reconstruction of the facility. If the agency confirms that the facility will undergo a reconstruction, the facility may be subject to New Source Performance Standards

("NSPS") (40 CFR Part 60), which impose emissions limitations and other requirements on the facility.

13. In this case, the proposed work on Piney Point's sulfuric acid plant is so extensive that it constitutes a reconstruction of the sulfuric acid plant. Under the applicable DEP regulations, DEP must review and approve Piney Point's plan for the reconstruction of the sulfuric acid plant before Piney Point commences work on the project. Further, the sulfuric acid plant must comply with the applicable New Source Performance Standards, including the requirements in DEP Rule 62-296.402, F.A.C. Piney Point's failure to obtain, and DEP's failure to demand, preconstruction approvals from DEP violates the requirements of Chapter 403, F.S., and Chapter 62, F.A.C., for the protection of the natural resources of the State of Florida.

COUNT II--MODIFICATION

14. All of the allegations in paragraphs 1-10, above, are adopted and incorporated herein by reference.

15. DEP Rule 62-204.800(7)(d), F.A.C., adopts by reference the provisions of 40 CFR 60.14, which define the term "modification." See also Rule 62-210.200(185), F.A.C. Subject to certain qualifications, 40 CFR 60.14 states that any physical or operational change to an existing facility is deemed to be a modification of that facility if the change results in an increase in certain emissions from the facility. Under the applicable DEP regulations, DEP must review and approve any plan

for the modification of a facility before the facility's owner commences construction of the modification. Further, certain modified facilities are subject to New Source Performance Standards.

16. In this case, the proposed work on Piney Point's sulfuric acid plant constitutes a "modification." The proposed modification of the sulfuric acid plant is subject to DEP's preconstruction review procedures. The modified facility is subject to New Source Performance Standards, including the provisions of DEP Rule 62-296.402, F.A.C. Piney Point's failure to obtain, and DEP's failure to demand, preconstruction approvals from DEP violates the requirements of Chapter 403, F.S., and Chapter 62, F.A.C., for the protection of the natural resources of the State of Florida.

COUNT III--MAJOR MODIFICATION

17. All of the allegations in paragraphs 1-10, above, are adopted and incorporated herein by reference.

18. The provisions of 40 CFR 52.21 and DEP Rule 62-212.400, F.A.C., establish the requirements for the DEP Prevention of Significant Deterioration ("PSD") program. Subject to various qualifications, a "major modification" is defined under the PSD program to include any physical change to (or change in the method of operation at) an existing facility that results in a significant net emissions increase of any pollutant regulated under the Clean Air Act. See 40 CFR 52.21(b)(2)(i) and Rule

62-212.400(2)(d), F.A.C. To determine whether there will be s significant net emissions increase, DEP must compare the facility's historical actual emissions to the facility's future potential emissions. Under the provisions of DEP Rule 62-212.440(5), F.A.C., DEP must review and approve any major modification to an existing facility before the commencement of construction on the major modification. Further, a facility that will undergo a major modification may be subject to the other substantive and procedural requirements established in the Prevention of Significant Deterioration programs.

18. In this case, Piney Point's plan involves a "major modification" of Piney Point's sulfuric acid plant. Piney Point cannot lawfully commence construction of the major modification until Piney Point complies with the applicable DEP preconstruction review requirements. Piney Point's failure to obtain, and DEP's failure to demand, preconstruction approvals from DEP violates the requirements of Chapter 403, F.S., and Chapter 62, F.A.C., for the protection of the natural resources of the State of Florida.

PRAYER FOR RELIEF

WHEREFORE, Manatee County respectfully requests the Department to:

1. Promptly decide that Piney Point's proposed project involves a reconstruction, modification, and major modification, which are subject to DEP preconstruction review requirements;

2. Enjoin Piney Point from commencing or proceeding with construction on the sulfuric acid plant until Piney Point complies with all of the applicable DEP rules and regulations; and

3. Provide Manatee County with prompt, actual notice of any decision that DEP makes concerning the merits of this complaint.

Respectfully submitted this 3rd day of March, 1997.

DAVID S. DEE
Florida Bar No. 281999
JOHN T. LAVIA, III
Florida Bar No. 853666
LANDERS & PARSONS
310 W. College Avenue
P.O. Box 271
Tallahassee, FL 32302
Phone: 904/681-0311
Fax: 904/224-5595

and

H. HAMILTON RICE, JR.
Florida Bar No. 325732
Manatee County Attorney
JEFFREY N. STEINSNYDER
Florida Bar No. 614210
Senior Assistant County Attorney
P.O. Box 1000
Bradenton, FL 34206
Phone: 941/745-3750
Fax: 941/749-3089

Attorneys for Manatee County

VERIFICATION

Under penalty of perjury, I declare that I have read Manatee County's Complaint and that the facts stated in it are true and correct to the best of my knowledge, information and belief.

By: Patricia M. Glass
Patricia M. Glass, Chairman
The Board of County Commissioners
of Manatee County

DISTRICT OF COLUMBIA

The foregoing instrument was acknowledged before me this 28th day of February, 1997, by Patricia M. Glass, who is personally known to me or who has produced Florida Drivers License as identification and who did take an oath.

Rachel L. Stewart
Notary Public in and for the District of Columbia

RACHEL L. STEWART
(Print Name)

My Commission Expires: My Commission Expires September 14, 1998

CERTIFICATE OF SERVICE

I hereby certify that the original and one copy of Manatee County's Verified Complaint were furnished by hand delivery to the Clerk, Department of Environmental Protection, 3900 Commonwealth Boulevard, Douglas Building, Tallahassee, Florida 32399 and copies were furnished by hand delivery to Douglas Beason, Assistant General Counsel, 3900 Commonwealth Boulevard, Douglas Building, Tallahassee, Florida 32399 and Paul Amundsen, Amundsen & Moore, 502 East Park Avenue, Tallahassee, Florida 32301 this 3rd day of March, 1997.

David L. Dee

Attorney

/vc:MANCOM2

LANDERS & PARSONS, P.A.
ATTORNEYS AT LAW

CINDY L. BARTIN
DAVID S. DEE
JOSEPH W. LANDERS, JR.
JOHN T. LAVIA, III
FRED A. McCORMACK
PHILIP S. PARSONS
ROBERT SCHEFFEL WRIGHT

HOWELL L. FERGUSON
OF COUNSEL

VICTORIA J. TSCHINKEL
SENIOR CONSULTANT
(NOT A MEMBER OF THE FLORIDA BAR)

310 WEST COLLEGE AVENUE
POST OFFICE BOX 271
TALLAHASSEE, FLORIDA 32302
TELEPHONE (904) 681-0311
TELECOPY (904) 224-5595

January 16, 1997

Mr. Douglas Beason, Esq.
Office of General Counsel
Department of Environmental
Protection
2600 Blair Stone Road
Twin Towers Office Building
Tallahassee, Florida 32399

Re: Piney Point Phosphates, Inc. (PSD-FL-144)

Dear Mr. Beason:

As you know, this law firm is helping the Board of County Commissioners of Manatee County ("County") with its evaluation of various environmental law issues concerning a proposal by Piney Point Phosphates, Inc. ("Piney Point"), to refurbish and restart a fertilizer manufacturing facility in Manatee County that was closed several years ago. Based on the correspondence to and from the Florida Department of Environmental Protection ("DEP"), which is attached hereto as Exhibits "A" and "B," it is our understanding that Piney Point met with DEP on December 10, 1996 to determine whether Piney Point may rebuild its existing sulfuric acid plant and then resume commercial operations, without obtaining any additional permits, permit modifications, or other approvals from DEP. It also is our understanding that DEP has not yet made a final determination about the permitting requirements that are applicable to Piney Point's plan.

This letter describes Manatee County's concerns about Piney Point's proposal.

I. SUMMARY

Piney Point's sulfuric acid plant was built before 1975. The plant was used sporadically in the 1980's. The plant "was down for major repairs and maintenance in February 1989" and, later that year, Piney Point submitted an application to DEP for authorization to construct a new sulfuric acid plant, which would permanently replace the existing plant. The existing plant closed in 1992 and has not resumed operations since that time. In the interim, Piney Point has pursued the DEP permits for its new plant.

In 1996, the U. S. Park Service and Manatee County alerted DEP that Piney Point had not conducted a proper "top-down" analysis of the Best Available Control Technology ("BACT") for Piney Point's new facility. Manatee County submitted a BACT analysis to DEP which demonstrated that the emissions limitations for Piney Point's new facility should be more restrictive than the emissions limitations that were proposed by Piney Point. Now it appears that Piney Point is prepared to abandon its plan to build a new sulfuric acid plant.

Piney Point now plans to spend $18,000,000 or more to rebuild and restart its old sulfuric acid plant. Substantial portions of the plant will be replaced. The magnitude of these repairs suggests that the plant currently is inoperable or, at best, unable to operate at its design capacity.

Piney Point's submittal to DEP does not adequately address the permitting issues that must be evaluated before DEP can determine whether Piney Point's proposal will trigger the application of various state and federal regulations, such as New Source Performance Standards ("NSPS") and Prevention of Significant Deterioration ("PSD"). Based on the limited information available at this time, it appears that Piney Point's plan to rebuild the existing sulfuric acid plant:

(a) may constitute a "reconstruction" of the facility, subject to NSPS requirements;

(b) will cause an increase in hourly emissions, subject to NSPS requirements for a "modification"; and

(c) will cause a significant net increase in annual emissions, subject to PSD requirements for a "major modification."

Under the applicable regulations, these issues must be addressed and resolved before Piney Point commences construction on the existing plant.

Manatee County respectfully requests DEP to carefully review all of the relevant facts and regulations before DEP makes any decisions concerning Piney Point's proposal to rebuild its sulfuric acid plant in Manatee County. The County also requests DEP to provide Manatee County with:

(a) written notice of any DEP decision concerning any proposal by Piney Point to construct, modify, refurbish, or operate any potential source of pollution at Piney Point's facility in Manatee County; and

(b) a clear point of entry into the administrative hearing process whenever DEP makes any determination concerning the applicability of any DEP regulations to Piney Point's facility.

Manatee County wants to work in a cooperative manner with DEP and Piney Point to evaluate the issues concerning Piney Point's proposed activities in Manatee County. However, Manatee County also wants to be positioned to exercise its legal rights and protect its substantial interests, if necessary.

All of these issues are discussed in more detail in the following sections of this letter.

II. FACTUAL BACKGROUND

Piney Point's existing sulfuric acid plant was built before 1975. The plant originally used a single absorption process to produce 1400 tons per day ("tpd") of sulfuric acid.[1] In 1975, DEP issued a construction permit that authorized the plant's owner to increase the plant's capacity to 2000 tpd and convert the plant to a double absorption process. This modification was completed by August 1976.[2]

---

[1] "Report In Support Of An Application For A PSD Construction Permit Review" prepared by Koogler & Associates for Royster Phosphates, Inc. (dated November 30, 1989) at page 4.

[2] Id.

We do not know whether there have been any modifications of the sulfuric acid plant since 1976. However, the former owner of the plant reported that:

> the sulfuric acid plant was down for <u>major repairs</u> and maintenance in February 1989, for approximately 415 hours.[3] (emphasis supplied).

In November 1989, the owner of the plant (i.e., Royster Phosphates, Inc., or "Royster") submitted an application to DEP for a permit to construct a new sulfuric acid plant. The permit application repeatedly states that the existing sulfuric acid plant "will be permanently shutdown when the new sulfuric acid plant is operational."[4]

The existing sulfuric acid plant was shutdown in 1992 and has not operated for more than four years.[5] Indeed, the operations of the plant have been sporadic since 1984. The 1989 permit application for the new facility states that 1984

> was the only year of full plant operation in the previous several years at the time of [PSD permit] application was submitted [sic] in 1989.[6]

Most recently, the plant's operations increased from 1988 (3982 hours) to 1990 (7875 hours), but then declined until 1992 (3410 hours), when the plant was closed.[7]

---

[3] Letter from Koogler & Associates to DEP (dated October 2, 1990) at page 2.

[4] "Report In Support Of An Application For A PSD Construction Permit Review" at pages 1 and 4.

[5] Letter from Koogler & Associates to DEP (dated April 24, 1995), Attachment 1 at page 1, §1.1.

[6] Letter from Koogler & Associates to DEP (dated October 2, 1990) at page 1.

[7] Letter from Koogler & Associates to DEP (dated April 24, 1995), Attachment 1 at page 1, §1.1.

The sulfuric acid plant and the related fertilizer manufacturing facilities have been owned by a succession of different companies. It is our understanding that Piney Point bought the facilities after the bankruptcy of the prior owner, Royster Phosphates, Inc.

The physical and operational condition of Piney Point's plant was suspect even before the plant shut down. Among other things, in 1989 a spill of sulfuric acid created a cloud of airborne pollutants, which compelled Manatee County to evaluate approximately 400 people from the area near the plant. Industrial accidents at the site have resulted in several injuries and deaths.

In a letter to DEP dated December 17, 1996, Piney Point identified "approximately 90% of the repair activities associated with the repair and restart" of the existing sulfuric acid plant.[8] Piney Point "anticipates expending approximately $18 million [$18,000,000] effecting these repairs."[9] According to Piney Point, "several plant components are currently proposed to be physically relocated" and, "due to technical obsolescence; some of the existing equipment or repair components are no longer available."[10] Piney Point's list of changes to the plant indicates that many components of the facility must be replaced completely (e.g., the boiler feedwater heater; the economizer; all three acid towers; all three mist eliminators; a heat exchanger; the condensate storage tank; the cooling tower; the acid coolers; the acid pump tanks; nine pumps; sixteen ducts; etc.).[11] Piney Point alleges in its letter that these "repairs" will not affect the plant's production capability or emissions, but Piney Point does not identify the production capability or emissions levels that it is using as the baseline for its comparison.

---

[8] Exhibit "A" at page 2.

[9] Id.

[10] Exhibit "A" at page 1.

[11] Exhibit "A", at pages 1-3 of Exhibit I.

III. MANATEE COUNTY'S CONCERNS

Manatee County believes that Piney Point's proposed work on the existing sulfuric acid plant may constitute a "reconstruction," "modification," or "major modification" of the facility, which would trigger the application of NSPS and PSD requirements. Each of these issues is discussed separately in the following sections of this letter.

This letter primarily focuses on the regulations in the federal NSPS and PSD programs, which have been adopted by reference in DEP's rules, because the U. S. Environmental Protection Agency's ("EPA") interpretations of the applicable federal regulations are more numerous and easier to locate than DEP's precedents.

A. Reconstruction Issues

We assume that Piney Point sent its letter to DEP ("Exhibit A") in part because Piney Point does not want its work on the existing sulfuric acid plant to be classified as a "reconstruction." Reconstruction is defined at 40 CFR 60.15(b)[12] as follows:

> (b) "Reconstruction" means the replacement of components of an existing facility to such an extent that:
>
> > (1) The fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility
> > . . .

---

[12] DEP Rule 62-204.800(7)(d), F.A.C., states that "the general provisions of 40 CFR Part 60, Subpart A, revised as of July 1, 1994, are adopted and incorporated by reference" into the DEP rules, subject to certain exceptions that are not relevant here. Thus, the federal definition and general provisions concerning a "reconstruction" apply to facilities in Florida.

If a reconstruction occurs, the plant "becomes an affected facility, irrespective of any change in emission rate." (emphasis supplied) 40 CFR 60.15(a).

In this case, Piney Point's letter does not contain enough information for DEP to determine whether a reconstruction will occur. First, Piney Point's letter does not identify all of the work and all of the costs associated with Piney Point's proposed project. Piney Point's letter acknowledges that the attached list of "repairs" includes only "approximately 90%" of the work that will be done on the existing sulfuric acid plant. Piney Point should be asked to identify all of the proposed changes to its existing plant and identify the anticipated costs associated with each of the proposed changes.

Second, Piney Point's letter and the attached affidavit appear to be based on an erroneous premise. The affidavit states that the cost of the work on the existing plant was compared to the cost of

> a new grassroots plant of the same capacity (2,000 TPD), design (double contact wet process) and emissions limitations. . . . (emphasis supplied).[13]

It is our understanding that Piney Point's existing plant does not use a "wet" process. A "wet gas plant" uses hydrogen sulfide as the source of sulfur.[14] Consequently, Piney Point's estimate of the cost of a comparable new facility may be in error.

Third, Piney Point's letter and affidavit do not indicate whether Piney Point's estimate includes the cost of modifications to the plant that have occurred in the past. To determine

---

[13] Letter dated December 17, 1996 from Piney Point, at Exhibit II.

[14] See §8.10 EPA Compilation of Air Pollutant Emission Factors, Volume 1 (5th Ed.); AP-42 (January 1995).

whether the work on Piney Point's plant constitutes reconstruction, Piney Point must calculate the cost of the changes that are currently proposed and add them to the cost of all of the changes that have occurred at the plant in the past.[15] The current proposals cannot be viewed in isolation.

Fourth, Piney Point's letter and affidavit are too conclusory in nature. Piney Point did not provide a detailed, itemized estimate of the cost of its proposed project or the cost of a new facility. Without itemized estimates, DEP cannot determine whether Piney Point's conclusions are valid.

Manatee County believes DEP should request additional, detailed information from Piney Point so that DEP can better evaluate Piney Point's proposal. Additional information is particularly important in this instance because Piney Point's estimated capital cost for this project (i.e., $18,000,000) is approaching 50% of the estimated cost of a new facility (i.e., $40,000,000) and thus it appears that Piney Point is approaching the regulatory threshold for a reconstruction. In addition, Piney Point should not be allowed to avoid the requirements associated with a reconstruction unless Piney Point can clearly demonstrate that its project does not constitute a reconstruction.

B. Modification Issues

Piney Point's letter to DEP does not directly address many of the issues that must be answered before DEP can determine whether Piney Point's activities constitute a "modification" that is subject to NSPS or PSD requirements.

---

[15] See generally letter from EPA to David S. Dee (dated August 24, 1996), which is attached hereto as Exhibit "C", at pages 3-4 (to determine whether changes to Tampa's resource recovery facility constituted a reconstruction, EPA requested Tampa to submit information concerning all costs of changes for each emissions unit from the time of initial startup in 1967 to the present).

1. NSPS Determination of a Modification

For NSPS analyses, 40 CFR 60.14(a)[16] provides as follows:

> Except as provided under paragraphs (e) and (f) of this section, any physical or operational change to an existing facility which results in an increase in the emission rate to the atmosphere of any pollutant to which a standard applies shall be considered a modification within the meaning of section 111 of the [Clean Air] Act. Upon modification, an existing facility shall become an affected facility for each pollutant to which a standard applies and for which there is an increase in the emission rate to the atmosphere.

Thus, as a general rule, any change that causes any increase in regulated emissions shall constitute a modification subject to NSPS requirements. The cost of the changes is not relevant to the determination of whether the changes are a modification.

There are exceptions to this general rule, but the exceptions do not apply to Piney Point's proposal. Most significantly, 40 CFR 60.14(e)(1) provides that routine "maintenance, repair, and replacement" is not a modification. This exception is not applicable here because the extensive changes proposed by Piney Point are not "routine." Indeed, many major components of the plant must replaced completely, including the boiler feedwater heater, the economizer, all three acid towers, all three mist eliminators, a heat exchanger, the condensate storage tank, the cooling tower, the acid coolers, the acid pump tanks, nine pumps, and sixteen ducts. The sheer magnitude of these replacements, together with the estimated minimum cost of $18,000,000, highlights the fact that Piney Point's proposed activities are not "routine."

---

[16] The provisions of 40 CFR 60.14 are adopted by reference in DEP Rule 62-204.800(7)(d), F.A.C.

For NSPS purposes, emissions increases are determined by comparing the plant's hourly emission rate immediately before and after the physical or operational changes to the plant.

> The EPA compares the hourly emissions of the unit at its current maximum capacity to its potential emissions at maximum capacity after the change. . . . In this calculation, the agency disregards the unit's maximum _design_ capacity; this factor often sheds little light on the unit's _actual current_ capacity to produce emissions." (emphasis in original)

Wisconsin Electric Power Company v. Reilly, 893 F.2d 901, 913 (7th Cir. 1990) (herein referred to as "_WEPCO_"). When establishing a plant's actual current capacity, EPA does _not_ consider the plant's original design capacity. _Id_. Similarly, EPA does _not_ establish the pre-renovation emissions of a plant by looking at "representative" emissions during prior years. _WEPCO_ at 913-915. Baseline emission rates for the plant "are determined by hourly maximum capacity just prior to the renovations." _WEPCO_ at 914.

Given the extensive changes that must be made to Piney Point's sulfuric acid plant before the plant can resume commercial operations, it is clear that the plant is in a state of considerable disrepair. We assume that, in its current deteriorated condition, this 1976 vintage plant is not capable of operating at its design capacity or complying with the applicable DEP emissions limitations. Indeed, the plant may not be capable of operating at all, unless the plant undergoes extensive non-routine repairs and improvements. Consequently, for NSPS purposes, the plant's "actual current capacity" appears to be zero. If so, Piney Point's non-routine changes to the plant will increase the plant's emissions, which will constitute a modification, which will make the plant subject to NSPS requirements.

If Piney Point contends that the plant can operate in its current condition, DEP should require Piney Point to conduct stack tests to establish the plant's "actual emissions." Without current stack test data, DEP cannot accurately determine whether the proposed changes to the plant will cause an emissions increase.

2. PSD Determination of a Modification

In accordance with 40 CFR §52.21(i)(2), the federal PSD and New Source Review (NSR) requirements apply to new sources of air pollution and "major modifications" of existing sources.[17] A "major modification" is defined as

> any physical change in 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 [Clean Air] Act.

40 CFR §52.51(b)(2)(i).[18] A "net emissions increase" is defined as the sum of "any increase in actual emissions from a particular physical change," together with any other "contemporaneous" increases or decreases in actual emissions. 40 CFR §52.21(b)(3). An increase or decrease in emissions is "contemporaneous" if

> it occurs between: (a) the date five years before construction on the particular change commences; and (b) The date that the increase from the particular change occurs.

40 CFR §52.21(b)(3)(ii).

These federal PSD regulations were described and applied by the U.S. Environmental Protection Agency ("EPA") in a 1992 memorandum (attached hereto as Exhibit "D") concerning the Cyprus Northshore Mining Corporation ("Cyprus"). In pertinent part, EPA explained that:

> Applicability of the PSD provisions must be determined in advance of construction and on a pollutant-by-pollutant basis. Specifically, to determine whether a proposed change at an existing source will result in

---

[17] The federal PSD and NSR requirements have been adopted by DEP in Rule 62-212.400, F.A.C.

[18] Under the PSD regulations, a major modification does not include "routine maintenance, repair and replacement." 40 CFR §52.21(b)(2)(iii)(a). This exemption does not apply here because Piney Point's project involves non-routine repairs and replacements.

> an increase in actual emissions, the source must first determine a baseline level of actual emissions. The applicable regulation defines actual emissions on a particular date as "the average rate, in tpy, at which the unit actually emitted the pollutant during a 2-year period which precedes the particular date and which is representative of normal source operation" [see 40 CFR 52.21(b)(21)(ii)]. The Administrator shall allow use of a different time period "upon a determination that it is more representative of normal source operation." [Ibid.] The EPA has "typically used the 2 years immediately preceding the physical or operational change to establish the baseline" [see 57 FR 32317].[19]

In the Cyprus case, EPA rejected Cyprus' argument that the baseline emissions could be established by looking at the facility's emissions before the "contemporaneous" period (i.e., more than five years before the proposed change to the facility). EPA explained its decision in the following terms:

> The EPA policy presumes a calculation based on the 2 years that immediately preceded the changes [see 45 FR 52676, 52705, 52718 (1980)].
>
> *　　*　　*　　*　　*　　*
>
> As discussed, the Administrator's power to use a different baseline period is limited to those circumstances where the source demonstrates that some time period other than the 2 years that precede the change is more representative of normal source operation. In general, EPA has indicated that this provision is to apply to catastrophic occurrences such as strikes and major industrial accidents. . . .

---

[19] Exhibit "D" at page 3.

* * * * * *

On the other hand, EPA has declined to consider a stop in operations, in and of itself, to constitute grounds to change the baseline years. For instance, in the WEPCO rulemaking, EPA adopted a presumption for utilities that considers any 2 years within the 5 years that precede the change to be representative of normal source operations. However, EPA rejected comments seeking to allow further accommodations for units that had been out of operation [see 57 FR 32325].

> The EPA disagrees with comments seeking to allow the use of any 2 consecutive years within the last 5 years of a unit's "operation" rather than within the 5 years directly preceding the proposed change. A shifting of the 5-year period would be difficult to harmonize with the definitions of contemporaneous contained in the regulations. This type of open-ended provision would even credit a unit which has been inoperative for 20 or 30 years or longer with a high level of emissions.[20]

In light of these considerations, EPA concluded that the baseline emissions for some of Cyprus' units were zero. EPA noted that:

> in the last 10 years the source [Cyprus] has been idle due to general economic conditions, and the zero source baseline appropriately reflects source utilization under these longstanding market conditions.[21]

[20] Exhibit "D" at pages 7 and 8.

[21] Exhibit "D" at page 8.

EPA rejected Cyprus' argument that Cyprus could calculate the facility's net emissions increases and decreases by looking at emissions changes that occurred outside the 5 year period for "contemporaneous" changes.[22] EPA noted that Cyprus' argument conflicts with the plain language of EPA's regulations.

> Moreover, allowing credit for very old emissions reductions undermines the purpose of the contemporaneous requirement by enabling new construction activity to burden the environment with levels of air pollution higher than they have been for many years.[23]

If we apply the EPA regulations and Cyprus analyses to the Piney Point proposal, it appears that Piney Point's baseline emissions are zero and any significant increase in emissions will trigger New Source Review requirements.

As noted in Cyprus, EPA's policy is to calculate "actual emissions" by looking at the facility's average emissions during the preceding two years. In this case, Piney Point's average emissions during the past two years have been zero.

EPA can consider a different baseline period, but EPA has indicated in Cyprus that a different baseline should be established only when there has been a "catastrophic" occurrence. In this case, Piney Point has not alleged and presumably cannot demonstrate that a catastrophic event has occurred.

Piney Point's decision to stop its operation for economic reasons is not sufficient justification to change the baseline years. Here, as in the Cyprus case, "the zero baseline appropriately reflects source utilization."[24]

Even if we consider Piney Point's emissions during the last five years, Piney Point's "actual emissions" will be quite small. In this hypothetical case, Piney Point's "actual emissions" are the "average rate, in tpy [tons per year] at which the unit actually emitted the pollutant during a 2-year period." Since

---

[22] Exhibit "D" at pages 6 and 7.

[23] Exhibit "D" at page 7.

[24] Exhibit "D" at page 8.

Piney Point's plant was not in operation for approximately 4.5 of the last 5 years, the average emissions rate for any two year period will include, at most, only about six months of emissions.

The baseline emissions rate for Piney Point's plant will be compared to the plant's potential to emit after the modification is completed. Since the plant previously was a major source, it seems highly probable that there will be a "significant" net emissions increase if Piney Point rebuilds its sulfuric acid plant and then operates the plant at its previously permitted levels. If there is a significant increase, the plant will be subject to PSD review pursuant to state and federal regulations.

C. <u>PSD Review for Shutdown Facilities</u>

Under EPA policy, a facility that has been shutdown for two years or more is presumed to be shutdown on a permanent basis. A facility that has been permanently shutdown must undergo PSD review as a new source before resuming operations. <u>See also</u> §62-210.300(6)(b), F.A.C.

EPA's policy and presumption should be applied in this case. Piney Point and its predecessors have stated since at least 1989 that they intended to "permanently shutdown the existing facility" as soon as the new sulfuric acid plant is available. Given the extensive non-routine repairs that are required to the existing plant, it appears that Piney Point intentionally allowed the old, existing plant to deteriorate over the past five years while Piney Point pursued the permits for the new facility. Since Piney Point cannot simply reactivate the existing plant and instead must rebuild it, Piney Point should not be allowed to evade the requirements for new sources nor should Piney Point be allowed to renew its operations at old, high levels of emissions.

IV. <u>CONCLUSION</u>

Manatee County would like to work with DEP to evaluate the issues that have been raised by Piney Point's proposal to rebuild the existing sulfuric acid plant. At this time, however, Manatee County and DEP do not have enough information to properly analyze Piney Point's proposal. For this reason, Manatee County respectfully requests DEP to take all appropriate steps to ensure that DEP has all of the relevant facts in hand before DEP makes any final determinations concerning the applicability of DEP's regulations to Piney Point's facility.

Manatee County also again respectfully requests DEP to provide Manatee County with written notice whenever DEP reaches any conclusions about the application of the NSPS and PSD regulations to Piney Point. Please note that Manatee County is entitled to notice and a clear point of entry into the administrative process, even if DEP decides that the NSPS or PSD regulations do not apply in this instance. See Manasota-88 v. Gardinier, Inc., 481 So. 2d 948 (Fla. 1st DCA 1986)(Manasota-88 is entitled to an administrative hearing to contest DEP's decision that an air permit is not required); Friends of the Hatchineha, Inc., v. Department of Environmental Regulation, 580 So. 2d 267 (Fla. 1st DCA 1991)(environmental group entitled to administrative hearing to challenge DER's decision that proposed driveway qualified for exemption from dredge and fill permitting process). Although Manatee County does not wish to engage in litigation with DEP, Manatee County does wish to preserve its right to pursue its administrative remedies, if necessary.

Thank you for your cooperation and assistance with this matter. Please call me if you have any questions. Manatee County would be happy to meet with DEP in Tallahassee or Tampa, at your convenience, to discuss these issues in more detail.

Sincerely,

D. S. Dee

David S. Dee

cc: Dr. Richard Garrity
Bill Thomas
Gerald Kissel
Howard Rhodes
Clair Fancy
Brian Beals, EPA
Scott Davis, EPA
Joyce Chandler, EPA OECA
Ellen Porter, National Park Service
Mike Solomon, EPA
Hamilton Rice, Jr.
Karen Collins
Paul Amundsen
Richard Moore

PINEY POINT PHOSPHATES, INC.

13300 U. S. Hwy. 41 North
Palmetto, Florida 34221
(941) 722-4555

CERTIFIED/RETURN RECEIPT NO. P 576 124 740

17 December 1996

Mr. W. C. Thomas, P.E., Administrator
State of Florida
Department of Environmental Protection
Division of Air Resources Management
Southwest District Office
3820 Coconut Palm Drive
Tampa, FL 33619

Re: Piney Point Phosphates, Inc.;
FDEP Permit No. A041-197112
Sulfuric Acid Plant

Dear Sir:

Piney Point Phosphates, Inc. (PPP) appreciates the opportunity and time you gave Company representatives on 10 December 1996 to discuss the forthcoming restart of the above-referenced sulfuric acid plant. As you may recall, PPP intends to repair the existing 2,000-ton-per-day sulfuric acid plant for restart in late 1997. PPP has identified several specific areas that will be repaired or equipment replaced to different configurations.

Due to technical improvements and safety considerations, several plant components are currently proposed to be physically relocated during repairs. PPP does not anticipate that these actions will in any way affect the plant production capability or alter the emissions from the source. Further, due to technical obsolescence, some of the existing equipment or repair components are no longer available.

Concomitant with the sulfuric acid plant repair will be repairs to the Sulfur Storage Tank operated under FDEP permit AO41-206854. PPP does not anticipate any changes in emissions or operations rate in this source after repairs.

EXHIBIT
A

PPP will also be installing an auxiliary boiler that is currently permitted under FDEP permit AC41-232096.

Attached as "Exhibit I" find a list and short description of the repairs. These repairs represent approximately 90% of the repair activities associated with the repair and restart. PPP anticipates expending approximately $18 million effecting these repairs, including installation of a new Sulfur Storage Tank and auxiliary boiler ($16 million without these later two items).

PPP has reviewed these repair costs in contrast to constructing a new grassroots sulfuric acid plant and found the costs to be less than 50% of an entirely new plant. Find as "Exhibit II" a professional engineer's certification of the estimated repair costs and estimated new plant costs associated with this project. Repairs will be made primarily by Monsanto Enviro-Chem Systems, the original designer and builder of the original plant.

In closing, we appreciate your taking time to discuss this matter with our representatives. Please consider the attached exhibits and foregoing information; then if further information or response is needed, please contact me. Thank you.

Sincerely,

Ivan Nance

Ivan Nance
Corporate Environmental Manager

/rmm

Attachments

bcc: R. Stewart
R. Moore
C. Masio
T. Baroody

EXHIBIT I

PROPOSED REPAIRS AND EQUIPMENT REPLACEMENT TO THE EXISTING SULFURIC ACID PLANT AT PINEY POINT

Note: These are the major repairs that are planned. They are not all inclusive, but comprise about 90% of the work that is proposed.

1. Sulfur Burner:	The existing unit will be retained and repaired.
2. Boiler Feedwater Heater:	A new heater of same size and similar design will replace the existing unit that will be demolished.
3. Waste Heat Boilers:	The two (2) existing boilers will be retained and repaired.
4. Economizer:	A new economizer of larger size and similar design will replace the existing unit which will be demolished.
5. Main Compressor:	The existing compressor will be retained and refurbished.
6. No. 1 Converter:	The existing unit will be retained. The 1st pass section (of four passes) will be replaced with high temperature materials. The remaining passes will be retained and refurbished. Catalyst will be replaced as necessary.
7. No. 2 Converter:	The existing unit will be retained and the converter floor repaired. All catalyst will be replaced.
8. Acid Towers:	All three (3) acid towers (drying, interpass absorption and final absorption) will be replaced with smaller size units of similar design and higher efficiency. The existing towers will be demolished. Two (2) towers will be relocated from on-top of the control room to separate free standing foundations.
9. Mist Eliminators:	New mist eliminators will be provided in all three of the new towers.
10. Heat Exchangers:	One new heat exchanger of smaller size and similar design will replace the existing unit that will be demolished. Two existing

heat exchangers will be retained and repaired.

11. Superheater: The existing unit will be retained and repaired.

12. Condensate System: A new condensate storage tank of larger size, similar design and different metallurgy will replace the existing unit that will be demolished. The condensate system will be of similar design.

13. Cooling Tower: A new tower of smaller flow and similar design .of higher efficiency will be installed in the area occupied by the previous unit, which was previously destroyed in a storm.

14. Acid Coolers: New coolers of a new design (shell & tube anodic protection) will replace the existing cast iron coolers which will be demolished.

15. Acid Pump Tanks: The two (2) existing pump tanks will be replaced with one (1) new pump tank integral to the new interpass tower/pump tank.

16. Acid Storage Tanks: The two (2) existing sulfuric acid storage tanks will be retained and repaired.

17. Plant Stack/ Water System: The stack will be retained and rehabilitated. The associated soft water system will be comprised of new softeners of similar capacity and design.

18. Pumps: New pumps will be installed as follows: sulfur pumps (3), common acid circulating pump (1), acid drain pump (1), product acid booster pump (1), cooling water pumps (2), and condensate transfer pump (1).

19. Ducts: Sixteen (16) ducts will be replaced. Four (4) new ducts of the same design will be moved to relocated towers. One duct will be of different metallurgy. One duct will be lenghtened and inlet bird screen replaced. All other ducts will be unchanged from original design.

20. Misc. Piping/Valves: New piping and valves of similar design and size will be moved to relocated acid towers and coolers.

21. SO2 Monitor: The existing monitor will be repaired with new retrofit solid state parts.

22. Office: A generator and air compressor will be removed and a new office will be constructed from the existing room.

23. Civil, Structural, Insulation, Electrical, Painting: New piling and foundations will be supplied for the new drying and certain support equipment. An existing foundation will be used for the new interpass tower/pump tank. Otherwise existing foundations will be utilized for the balance of the plant. Most existing structural steel will be retained and rehabilitated; certain steel will be replaced where needed. Most insulation will be removed and replaced with new insulation. A new motor control center (MCC) will be installed adjacent to existing MCC in the same building; new lighting will be provided; new electrical tray, conduit and cable will be provided for new power, control and instrumentation wiring. All new equipment, vessels, steel, piping and ductwork, as well as existing support and access steel, will be painted.

24. Instrumentation: A new electronic system (distributive control-solid state) will replace the existing pneumatic system.

PROPOSED REPAIRS AND EQUIPMENT REPLACEMENT OF ITEMS ASSOCIATED WITH THE EXISTING SULFURIC ACID PLANT AT PINEY POINT

1. **Auxiliary Boiler:** A new package boiler rated at 190 MMBtu/hour will replace the existing 96 MMBtu/hour boiler. Note that PPPI is already permitted for the larger boiler (Permit No. AC41-232096).

2. **Sulfur Tank and Pit:** A new tank of the same size and similar design will replace the existing tank that will be demolished; The existing sulfur pit will be retained and repaired with similar designed coils and cover. Note that the sulfur storage tank is covered under Permit No. AO41-206854.

EXHIBIT II

CERTIFICATION OF COST OF PROPOSED REPAIRS AND EQUIPMENT REPLACEMENT TO THE EXISTING SULFURIC ACID PLANT AT PINEY POINT

The undersigned, being a duly registered professional engineer in the State of Florida, hereby certify that I am experienced in the design, construction and operation and maintenance of sulfuric acid plants. In my professional opinion, the repairs and equipment replacements to the existing sulfuric acid plant at Piney Point, estimated to cost approximately $16.9 million; will not exceed 50% of the cost of building a new grassroots plant of the same capacity (2,000 TPD), design (double contact wet process) and emission limitations (currently permitted limits) on the current Piney Point site. Based on my professional opinion, and the review of independent contractor proposals, the construction of a new grassroots plant having the preceeding specifications will cost in excess of $40 million.

The cost of the repairs and replacement equipment ancillary to the sulfuric acid plant (auxiliary boiler and sulfur tank/pit) are estimated to cost about $1.3 million.

Signed

Gerald W. Hartman

Gerald W. Hartman
December 13, 1996

Registered Professional Engineer in the State of Florida
License No. PE 48452

Department of Environmental Protection

Lawton Chiles
Governor

Southwest District
3804 Coconut Palm Drive
Tampa, Florida 33619

Virginia B. Wetherell
Secretary

December 19, 1996

Mr. Ivan Nance
Mulberry Phosphates, Inc.
P.O. Drawer 797
Mulberry, FL 33860

RE: Permitting of Piney Point Sulfuric Acid Plant Repairs/Renovations

Dear Mr. Nance:

From our meeting of December 10, 1996, it appears that the proposed repairs/renovations will not involve air permitting, with the following possible exceptions:

1) Any significant new emission unit, or a change involving a modification (as defined in the air rules) would require a construction permit (which includes public notice). A new molten sulfur tank could fall in this category.

2) The only construction permit applicable to this facility is AC41-2042B, dated 9/1/75, expired 9/1/76. This permit is referenced in our files but we do not have a copy. If there are specific limits/specifications in that permit which the proposed project would revise, that would probably require a construction permit. By this letter, I'm requesting that you and Manatee County check as to whether you have a copy of that permit.

If you have any questions, please call me at (813) 744-6100, Extension 107.

Sincerely,

Gerald Kissel, P.E.
District Air Engineer

cc: Manatee County

c:\piny1296

EXHIBIT B

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

REGION 4

345 COURTLAND STREET, N.E.
ATLANTA, GEORGIA 30365

AUG 20 1996

4APT-AEB

Mr. David S. Dee
Landers and Parsons
310 West College Avenue
P.O. Box 271
Tallahassee, Florida 32303

SUBJ: McKay Bay Refuse to Energy Facility

Dear Mr. Dee:

This letter is in response to your correspondence to the U.S. Environmental Protection Agency (EPA), dated April 2, 1996, requesting an applicability determination for the above referenced facility. Your correspondence requested an applicability determination pursuant to 40 C.F.R. §60.5 with regard to the retrofitting of equipment at the existing McKay Bay Refuse to Energy facility located in Tampa, Florida.

This determination is primarily based on the federal rule for municipal waste combustors (MWC's), promulgated on December 19, 1995, in the Federal Register under 40 C.F.R. Part 60, Subparts Cb (Emission Guidelines and Compliance Schedules for MWC's) and Eb (Standards of Performance for MWC's for Which Construction is Commenced After September 20, 1994). The rule contains the emission guidelines (EG) for existing MWC sources and the new source performance standards (NSPS) for new MWC sources. In addition to our review and interpretation of these federal regulations with regard to the proposed retrofit at the McKay Bay facility, to ensure national consistency, EPA Region 4 consulted with the Office of Enforcement and Compliance Assurance (OECA) and the Office of General Counsel (OGC), and received technical assistance from the EPA Office of Air Quality Planning and Standards (OAQPS).

Background: Reference Definitions and Concepts

The resultant applicability determination is derived directly from specific portions of the federal rule for MWC's. As a reference, the MWC applicability and the "MWC unit," "Modification," and "Reconstruction" definitions from the federal rule are included in this section.

Under 40 C.F.R. §60.51b, the boundaries of a municipal solid waste combustor are defined as follows:

EXHIBIT C

The MWC unit includes, but is not limited to the municipal solid waste fuel feed system, grate system, flue gas system, bottom ash system, and the combustor water system. The MWC boundary starts at the municipal solid waste pit or hopper and extends through:

(i) the combustor flue gas system, which ends immediately following the heat recovery equipment, or if there is no heat recovery equipment, immediately following the combustion chamber

(ii) the combustor bottom ash system, which ends at the truck loading station or similar ash handling equipment that transfer the ash to final disposal, including all ash handling systems that are connected to the bottom ash handling system

(iii) the combustor water system, which starts at the feed water pump and ends at the piping exiting the steam drum or superheater

The MWC unit does not include air pollution control equipment, the stack, water treatment equipment, or the turbine-generator set.

Under 40 C.F.R. §60.51b, Modification (or Modified MWC Unit) and Reconstruction are defined as follows:

Modification or Modified MWC Unit means a MWC unit to which changes have been made after June 19, 1996, if the cumulative cost of the changes, over the life of the unit, exceed 50 percent of the original cost of construction and installation of the unit (not including the cost of any land purchased in connection with such construction or installation) updated to current costs; or any physical change in the MWC unit or change in the method of operation of the MWC unit [that] increases the amount of any air pollutant emitted by the unit for which standards have been established under section 129 or section 111. Increases in the amount of any air pollutant emitted by the MWC unit are determined at 100 percent physical load capability and downstream of all air pollution control devices, with no consideration given for load restrictions based on permits or other nonphysical operational restrictions.

Reconstruction means rebuilding a MWC unit for which the reconstruction commenced after June 19, 1996, and the cumulative costs of the construction over the life of the unit exceed 50 percent of the original cost of construction and installation of the unit (not including any cost of land purchased in connection with such construction or installation) updated to current costs (current dollars).

Under 40 C.F.R. §60.50b, the applicability of the MWC guidelines and standards are outlined, to exclude certain actions:

> (d) Physical or operational changes made to an existing MWC unit primarily for the purpose of complying with emission guidelines under subpart Cb are not considered a modification or reconstruction and do not result in an existing MWC unit becoming subject to this subpart.

As the definitions state, the determination of the occurrence of a modification/reconstruction at a MWC unit is based on a cost analysis process. This process includes four steps:

(1) Determine the original construction and installation costs for the unit.

(2) Aggregate all costs of changes to the unit since start-up, including all costs for the emission guidelines.

(3) Subtract the "allowed" retrofit costs required for compliance with the emission guidelines.

(4) Compare the cost of changes to the unit since start-up to the original cost of the unit. If this value is greater than 50 percent of the original cost then a modification/reconstruction has occurred.

Your correspondence addresses the "allowed" retrofit costs (in step 3), but does not address the other costs (in item 2) for McKay Bay. This response will address all aspects of the cost analysis process.

<u>1985 Conversion to Waste-to-Energy Facility</u>

The McKay Bay Refuse-to-Energy Facility was originally constructed in 1967 as a solid waste combustor without heat recovery. The original facility included three combustion units, each with a capacity of 250 tons per day of municipal solid waste. This facility was in operation from 1967 until it ceased operation in 1979. In 1985, the facility began operations after being converted to a waste-to-energy facility. This conversion included the replacement of three Volund rotary kiln combustion units and the installation of one new Volund kiln unit (250 tons per day capacity) at the facility. A waste heat recovery system, a turbine generator, and four electrostatic precipitators were also installed during the conversion. Under the federal MWC rule, the cumulative costs of the changes at McKay Bay are included in determining the occurrence of a modification/reconstruction. The original three combustion units began operation in 1967; the fourth unit began operation in 1985. In order to complete the applicability determination of the subpart Cb emission guidelines or subpart Eb performance standards under the "cumulative cost" criteria, we are requesting the submittal of information outlining the waste-to-energy conversion costs and other modification costs for each combustion unit from the initial start-up dates of 1967 (for units 1, 2, and 3) and 1985 (for unit 4) through June 18, 1996.

Applicability Determination: Source Retrofit Categories

This section will initially outline our applicability determination, formulated in response to your question concerning whether the proposed retrofit improvements at McKay Bay would constitute modification/reconstruction of the MWC unit under the EG. Under the potential retrofit improvements discussed in your correspondence, categories for these improvements have been developed. These categories are:

(1) Improvements to components that are not part of the definition of a MWC unit, are being undertaken to comply with the EG, and are not considered part of potential costs of modification/reconstruction. This category has been determined to include the following potential improvements:

- Air Pollution Control Equipment
- Continuous Emissions Monitors
- Induced Draft Fans
- Electrical System (portions)
- Combustion Control Systems (portions)

(2) Improvements to components that are part of the definition of a MWC unit, are being undertaken to comply with the EG, and are not considered part of potential costs of modification/reconstruction. This category has been determined to include the following potential improvements:

- Auxiliary Burners
- Furnace, Grates, and Kilns
- Boiler and Economizer
- Ash Enclosures
- Ash Conveyor System

(3) Improvements to components that are not part of the definition of a MWC unit, are not being undertaken to comply with the EG, and are not considered part of potential costs of modification/reconstruction. This category has been determined to include the following potential improvements:

- General Equipment and Maintenance Building
- Control Room Systems

- Ash Building
- Ash Treatment System
- Tipping Floor

(4) Improvements to components that are part of the definition of a MWC unit, are not being undertaken to comply with the EG, and are considered part of potential costs of modification/reconstruction. This category has been determined to include the following potential changes and improvements:

- Furnace Configuration
- Refuse Pit
- Cranes

Within these four categories, for the purposes of determining whether or not this facility meets the criteria for modification/reconstruction under 40 C.F.R. §60.51b, the potential source improvements identified in Category 4 only would be considered a part of the potential costs of modification/reconstruction at the McKay Bay facility. In addition, the cumulative costs of changes over the life of the unit from the initial construction date through June 18, 1996, would be included in the potential costs of modification/reconstruction at the McKay Bay facility. A summary of the potential source improvements and their applicability criteria within this determination for the McKay Bay facility is presented in Table 1.

Applicability Determination: Discussion

Different interpretations are apparent when comparing our determination and the proposed determination in your correspondence. The basis for EPA's determination regarding the potential source improvements at the McKay Bay facility will be discussed in this section.

Category 1 Improvements: Air pollution control equipment is specifically excluded from the MWC unit definition and is being installed for compliance with the EG. Continuous emissions monitors are being installed specifically for compliance with the EG. As the rule (at §60.51b) is written, induced draft fans are not part of the MWC unit definition. This exclusion does not set a precedent however, for applicability to other NSPS boundary determinations. This exclusion is only for sources affected under subparts Cb, Ea, and Eb. The portions of the electrical system that are being installed for compliance with the EG (for compatibility with the new air pollution control system) are excluded from consideration as a modification/reconstruction. No costs associated with these potential improvements are included in modification/reconstruction cost calculations. In addition, control systems for the combustion units and the air pollution control equipment are not included in the MWC unit definition, thus their costs can be excluded.

Category 2 Improvements: Auxiliary burners are included in the MWC unit definition and are being installed for compliance with the EG for the maintenance of good combustion practices. The furnaces, grates, and kilns are included in the MWC unit definition and are being installed primarily for compliance with the EG to meet the new emission limits. The boiler and economizer are included in the MWC unit definition and are being installed for compliance with the EG to maintain compatibility with the furnace system upgrades. The ash enclosures are included in the MWC unit definition and are being installed for compliance with the EG for the control of fugitive ash emissions. The ash conveyor system is included in the MWC unit definition and is being installed for compliance with the EG for the control of fugitive ash emissions. No costs associated with these potential improvements are included in modification/reconstruction cost calculations.

Category 3 Improvements: General equipment improvements and the maintenance building are excluded from the MWC unit definition and are not being installed or improved for compliance with the EG. The control room systems are excluded from the MWC unit definition and are not being installed for compliance with the EG. The ash building is excluded from the MWC unit definition, is not being installed primarily for compliance with the EG, and is not primarily for the control of fugitive ash emissions (fugitive ash emissions are controlled by the ash conveyor system enclosures). The ash treatment system will be installed in the ash building and will treat fly ash prior to its combination with bottom ash, dewatering, and disposal. The ash treatment system, however, does not constitute a part of the ash handling system. The ash treatment system is excluded from the MWC unit definition and is not being installed primarily for compliance with the EG. The tipping floor is specifically excluded from the MWC unit definition and is not being improved for compliance with the EG. No costs associated with these potential improvements are included in modification/reconstruction cost calculations.

Category 4 Improvements: The furnaces are specifically included in the MWC unit definition, however, a change in the existing furnace configuration would not be completed primarily for compliance with the EG.[1] Furnace configuration changes, such

---

[1] The McKay Bay facility is currently configured with four combustion units, each with a capacity of 250 tons per day.

as a change to either three units each with 333 tons per day capacity or two units each with 500 tons per day capacity, are a fundamental change to the MWC units at McKay Bay. These furnace configuration changes require a "unit by unit" comparison of costs to an existing 250 tons per day capacity unit at McKay Bay. Therefore, all costs associated with this potential change are included in modification/reconstruction cost calculations.

The intent of the rule was to include the refuse pit or the hopper, whichever occurs first, specifically in the MWC unit definition. Improvements to the refuse pit would not be done primarily for compliance with the EG. Therefore, all costs associated with this potential improvement are included in modification/reconstruction cost calculations.

Cranes are specifically included in the MWC unit definition as part of the fuel feed system. Any improvements to the cranes would not be done for compliance with the EG. All costs associated with this potential improvement are included in modification/reconstruction cost calculations.

Applicability Determination: Modification/Reconstruction Costs

On the basis of the definitions of modification and reconstruction in 40 C.F.R. §60.51b and our analysis of the proposed retrofit at the McKay Bay facility, the following improvements have been determined to be considered in the modification/reconstruction cost analysis: Furnace Configuration Change, Refuse Pit, Cranes. This cost comparison is to be completed on a "unit by unit" basis, comparing each existing unit's original cost of construction and installation (not including any cost of land purchased in connection with such construction or installation) updated to current costs (current dollars) to the replacement or modified unit's cumulative costs of changes over the life of the unit. These cumulative costs of changes over the life of the unit are not to exceed the threshold level of 50 percent of the original unit's updated current cost for a source to remain subject to the EG.

In response to your queries regarding original unit costs, new facility costs, and current dollars computations, EPA has the following responses:

(1) There are two separate original costs for the MWC units at McKay Bay. The cost of the three original combustion units may be determined from the comparison of originally issued bonds for the construction of the facility, as originally constructed in 1967 as a solid waste combustor. For the fourth combustion unit, constructed new in 1985, its original cost is determined from this baseline date (1985). For the McKay Bay facility, however, a better comparison

cost may be determined from an accurate estimate of the cost of a new MWC facility of comparable design.

(2) To determine the fixed capital cost required to construct a comparable entirely new MWC facility, reference the EG proposal from September 20, 1994, of the Federal Register. On page 48240, Tables 3A and 3B outline the Capital and Annualized Costs of Air Pollution Control For Typical New and Existing Large and Small MWC Plants.

(3) The method for performing a cost update to current dollars can be selected by the source. Provided the appropriate historical and financial documentation is included, the ENR Construction Price Index can be used.

We look forward to your submittal of additional data to complete the subpart Cb/Eb applicability determination. If you have any questions or comments concerning this response, please contact either Mr. Brian Beals or Mr. Scott Davis of my staff at (404) 347-3555, extensions 4167 or 4144, respectively.

Sincerely,

Winston A. Smith
Winston A. Smith
Director
Air, Pesticides and Toxics
Management Division

Enclosure

cc: Joyce Chandler, OECA
Leslye Fraser, OGC
Walt Stevenson, OAQPS
Clair Fancy, Florida DEP
Iwan Choronenko, Hillsborough County EPC
Jerry Campbell, Hillsborough County EPC

TABLE 1

Potential Source Improvement	Defined under "MWC Unit"?	For EG Compliance?	Include in Reconstruction?
Air Pollution Control Equipment	NO	YES	NO
Continuous Emissions Monitors	NO	YES	NO
Auxiliary Burners	YES	YES	NO
Induced Draft Fans	NO	YES	NO
General Equipment and Maintenance Building	NO	NO	NO
Furnaces, Grates, and Kilns	YES	YES	YES
Furnace Configuration	YES	NO *	YES *
Boiler and Economizer	YES	YES	NO
Electrical System	NO *	YES	NO
Control Room Systems	NO *	NO *	NO
Control Systems (APC/Combustor)	NO *	YES	NO
Ash Building	NO	NO *	NO
Ash Enclosures	YES *	YES	NO
Ash Conveyor System	YES	YES	NO
Ash Treatment System	NO	NO	NO
Tipping Floor	NO	NO	NO
Refuse Pit	YES *	NO	YES *
Cranes	YES *	NO	YES *

* Differences exist between Determinations by EPA and the Source

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
Office of Air Quality Planning and Standards
Research Triangle Park, North Carolina 27711

AUG 11 1992

MEMORANDUM

SUBJECT: Proposed Netting for Modifications at Cyprus Northshore Mining Corporation, Silver Bay, Minnesota

FROM: John Calcagni, Director
Air Quality Management Division (MD-15)

TO: David Kee, Director
Air and Radiation Division, Region V (5A-26)

This memorandum responds to your July 2, 1992 inquiry regarding the applicability of the prevention of significant deterioration (PSD) program to proposed construction at a taconite ore processing facility owned and operated by Cyprus Northshore Mining Corporation (Cyprus) in Silver Bay, Minnesota. Cyprus proposes to modify its existing source by installing two new rotary hearth furnaces at the facility. To prevent this physical change from resulting in an increase in emissions and thus subjecting the source to PSD as a "major modification," Cyprus seeks to take credit for the shutdown of several, existing straight-grate furnaces which would be replaced as part of the proposed work. Since these furnaces have not operated since 1982, you have asked whether Cyprus may use the 1981 and 1982 actual emissions of these furnaces to establish the netting credit. Subsequent to your memorandum, counsel for Cyprus has written Region V urging the Environmental Protection Agency's (EPA's) approval of a baseline using actual emissions from these furnaces during the period of July 1975 to June 1977. However, after reviewing both the facts as presented to me, as well as the appropriate regulations and statutory provisions, it does not appear that either suggested baseline is appropriate. Indeed, for the reasons set forth in this memorandum, it does not appear that Cyprus can be credited with any emissions reductions stemming from the removal of the existing furnaces at the West Plant.

EXHIBIT
D

FACTUAL BACKGROUND[1]

The taconite ore processing facility at issue is a single major stationary source consisting of an East Plant and a West Plant. Reserve Mining (Reserve)--the owner before Cyprus--originally produced oxidized iron ore pellets from both plants. According to Cyprus, which took over the plant in 1989, Reserve operated the plant at near capacity until the mid-1970's when production began to decline due to an economic downturn in the domestic steel industry, labor unrest, and the installation of pollution control equipment. Finally, in 1982, Reserve shut down the West Plant operations due to poor market conditions. Reserve continued to manufacture pellets in the East Plant and maintained the equipment in the West Plant through 1986. At that point the company went bankrupt.[2]

Cyprus purchased the facility in 1989 and resumed operations in the East Plant in 1990. The West Plant operations were never resumed. Indeed, in 1989, the Minnesota Pollution Control Agency issued an air permit to Cyprus that apparently prohibited operation of four of the six furnaces at the West Plant.

Cyprus now proposes to restart manufacturing at the West Plant. To this end, the company wants to install two new rotary hearth furnaces as part of a switch to a direct reduction pellet process. [Cyprus currently has an option for the direct reduction technology which must be exercised before the end of this year.] The new West Plant furnaces will have significant nitrogen oxides (NO_x) and sulfur dioxide (SO_2) emissions. According to Region V and Cyprus, the potential-to-emit for the two new furnaces standing alone greatly exceeds the 40 tons-per-year (tpy) significance level applicable to both SO_2 and NO_x [see 40 CFR 52.21(b)(23)(i)]. Cyprus proposes to avoid PSD review by netting the emissions from the two new rotary hearth furnaces against the emissions associated with the shutdown of three of the existing furnaces that will be removed from the West Plant as part of the proposed renovation.

---

[1] This statement of the facts is based on your memorandum to me dated July 2, 1992 and the July 27, 1992 letter Region V received from Denise W. Kennedy and Robert T. Connery, counsel for Cyprus. The Office of Air Quality Planning and Standards has made no independent effort to verify this factual information.

[2] Prior to the bankruptcy, the union representing the workers at the West Plant filed a grievance against Reserve seeking severance pay on the grounds that the West Plant had been permanently shut down. However, in February 1986, the Iron Ore Industry Board of Arbitration ruled that Reserve did not at that time intend to permanently shut down the West Plant.

STATUTORY AND REGULATORY BACKGROUND

The PSD program [Clean Air Act (CAA), sections 160-169] applies in attainment areas [i.e., those areas which have attained the national ambient air quality standards (NAAQS)]. The new source review (NSR) requirements apply to newly-constructed sources and to "major modifications," physical or operational changes occurring at existing sources that result in significant net emissions increases. The PSD definition of modification contemplates a two-step test for determining whether activities at an existing facility constitute a major modification subject to review. In the first step, the reviewing authority determines whether a physical or operation change will occur. If so, the reviewing authority proceeds to determine whether a physical or operational change will result in an emissions increase over baseline levels. Routine changes and certain other changes are excluded by regulation from the definiton of physical or operational change (see 57 FR 32314, 32316). In this second step, EPA regulations focus on whether the proposed change will result in a "significant net emissions increase of any pollutant subject to regulation under the CAA" [see 40 CFR 52.21(b)(2)(i)]. A "net emissions increase" is defined as the increase in "actual emissions" from the particular physical or operational change, together with any other "contemporaneous" increases or decreases in actual emissions [see 40 CFR 52.21(b)(3)(i)]. To be "contemporaneous," the emissions increases or decreases must have "occurred" within the 5 years preceding the proposed change [see 40 CFR 52.21(b)(3)(ii)].

Applicability of the PSD provisions must be determined in advance of construction and on a pollutant-by-pollutant basis. Specifically, to determine whether a proposed change at an existing source will result in an increase in actual emissions, the source must first determine a baseline level of actual emissions. The applicable regulation defines actual emissions on a particular date as "average rate, in tpy, at which the unit actually emitted the pollutant during a 2-year period which precedes the particular date and which is representative of normal source operation" [see 40 CFR 52.21(b)(21)(ii)]. The Administrator shall allow use of a different time period "upon a determination that it is more representative of normal source operation." [Ibid.] The EPA has "typically used the 2 years immediately preceding the physical or operational change to establish the baseline" (see 57 FR 32317).

Because the applicability determination must be made in advance of construction, EPA's PSD regulations provide that when an emissions unit "has not begun normal source operations," actual emissions equal the "potential-to-emit" of the unit [see 40 CFR 52.21(b)(21)(iv)]. In other words, to determine if there is an emissions increase, the regulations require EPA to compare the source's actual emissions before the change and its potential emissions after the change. This is the so-called "actual-to-potential" test. This test, in effect, presumes that following the change the source will operate at 100 percent of its physical capacity. The source owner may overcome this presumption by agreeing to federally-enforceable restrictions that would prevent the plant from significantly exceeding its pre-modification emissions baseline.[3]

The determination of whether the physical or operational change would result in an increase in actual emissions is but one factor in determining whether the change will increase emissions. As mentioned, if the change will, standing alone, result in an increase in emissions, the source must next identify and quantify any other prior increases and decreases in "actual emissions" that are "contemporaneous" with the particular change and which are otherwise creditable [see 40 CFR 52.21(b)(3)(i) and (b)(21)]. Reductions are not creditable if the Administrator "has relied on it in issuing a permit" and that permit remains in effect at the time of the proposed change [see Id. at 52.21(b)(3)(iii)]. Also, reductions must have "approximately the same qualitative significance for public health and welfare as that attributed to the increase from the particular change" [see Id. at 52.21(b)(3)(vi)(c)].

It should be noted that the initial inquiry as to whether the change, standing alone, will result in an increase in actual emissions is calculated by determining the emissions increase at the particular emissions units to be changed or added [see

---

[3] In Puerto Rican Cement Co. v. EPA, 889 F.2d 292 (1st Cir. 1989), the court of appeals upheld EPA's application of the actual-to-potential test in a case involving modernization of cement kilns. However, in Wisconsin Elec. Power Co. (WEPCO) v. Reilly, 893 F.2d 901 (7th Cir. 1990), a different appeals court struck down EPA's actual-to-potential test as it applied to "like-kind" modifications at utilities. In a subsequent rulemaking, EPA adopted an "actual-to-future-actual" test for utility modifications to existing sources. Under that test, EPA compares the pre-change actual emissions baseline to a projection of future emissions that is based on the unit's past operating history and other factors (see 57 FR 32314). Even ignoring the fact that this rule is limited to electric steam generating units, the actual-to-future-actual test would be inapplicable here since Cyprus is essentially proposing to add a new furnace rather than merely making changes to the existing furnaces at the West Plant. Because it is impossible to reliably project future levels of capacity utilization and, hence, actual emissions at a new unit that has no past operating history, EPA's recent rulemaking retains the actual-to-potential test when the change at issue is the addition of a new emissions unit (see id., at 32323).

40 CFR 52.21(b)(21); NSR Workshop Manual, p. A.46 (Draft October 1990)]. The subsequent netting calculation includes all increases and decreases--anywhere at the source--that are contemporaneous and creditable [see 40 CFR 52.21(b)(3)(i); Workshop Manual at A.46-47].

DISCUSSION

A. General Applicability of PSD

As discussed, the first question is whether the work proposed constitutes a physical or operational change. This must be answered in the affirmative. The source proposes to add two new rotary furnaces and make all necessary changes to the West Plant to operate these new additions. This is not a case where the source is reactivating a shut-down facility and making only "routine" changes to bring it back on line. For this reason, there is no dispute that this new construction constitutes a physical change.

The second step is to determine whether this physical change will result in an increase in actual emissions at the emissions units affected. Here again, the answer is <u>yes</u>. Based on the description of the project we have, it appears that the work at issue is the installation of a direct reduction pellet process, including two new emissions units--two new rotary hearth furnaces.[4] Since these emissions units are new, their baseline level of actual emissions is zero. As discussed, their potential emissions are over the significance levels, so the proposed work will trigger PSD, unless there are contemporaneous increases and decreases at the source that can be used to net out of review.

B. Using the Shutdown of the West Plant as a Contemporaneous Decrease

Since the project, standing alone, will result in a significant increase in emissions, Cyprus must identify sufficient contemporaneous decreases to avoid PSD. The company urges EPA to credit the reductions associated with the removal of several existing furnaces at the West Plant. However, as discussed below, these reductions are neither contemporaneous nor otherwise creditable. Moreover, even if these reductions were eligible to be considered for netting, they would have no value since the baseline for the West Plant furnaces is zero.

---

[4] Cyprus does not contest that the work at issue involves the installation of new units rather than the rehabilitation of the existing emissions units.

1. Netting Reductions Cannot "Occur" Outside the Contemporaneous Period

The EPA's regulations limit netting to those emissions reductions that occur within the 5-year period that precedes the proposed change:

> An increase or decrease in actual emissions is contemporaneous with the increase from the particular change only if it occurs between: a) The date 5 years before construction on the particular change commences; and b) the date that the increase from the particular change occurs.

[see 40 CFR 52.21(b)(3)(ii)(emphasis added)]. Thus, if the reduction occurred more than 5 years before the commencement of construction of the proposed change, it is not contemporaneous. Here, the reduction undeniably took place in 1982 when the emissions from the West Plant fell to zero. This is outside the 5-year window. However, Cyprus contends that a reduction does not occur "until such time as the source determines not to resume operation of the equipment in question, or the source is, in some other way, precluded from operation of the equipment." In other words, a credible reduction does not "occur" when emissions decrease. It occurs when the source elects to take credit for it.

In Alabama Power Co. v. Costle, 636 F.2d 323, (D.C. Cir. 1979), the court recognized that EPA has substantial discretion in applying the plantwide bubble concept so as to reconcile the statutory goals of preserving clean air and providing for economic growth [see Id. at 400-03]. In particular, the court noted that EPA should enable emissions increases from the addition of a new unit to be set off by decreases resulting from the abandonment of an old unit [Id. at 401]. However, the court also emphasized that offset reductions claimed by industry to net out of review must be "substantially contemporaneous" (Id. at 402) (emphasis added). The EPA's regulations implemented this standard by setting 5 years, plus time for construction, as the period of contemporaneity. The EPA selected 5 years (despite proposing a 3-year period) on the basis that 5 years would be long enough to accommodate "corporate expansion planning" and would "minimize any incentive for keeping old or obsolete equipment in operation beyond its usefulness" (see 45 FR 52701). On the other hand, EPA declined to expand the contemporaneous period to any prior reduction that had occurred at the plant:

> [Industry commenters] urged EPA to treat any emissions decrease which occurs before a proposed increase as being "contemporaneous" with that increase. The EPA, however, has rejected those urgings. To credit any

> decrease that occurs before a proposed increase would violate any common sense notion of what is "contemporaneous," since a period of contemporaneity must have some definite boundaries.

[Ibid. (emphasis in original)]. Cyprus' interpretation of this provision violates this common sense understanding of a limited contemporaneous period. Under Cyprus' interpretation, sources could bring in any prior reduction, no matter how old or obscure, so long as the source retained the legal right to return to that emissions level.

Cyprus' proposed interpretation of EPA's regulations conflicts with the plain meaning of the contemporaneity requirement. Moreover, allowing credit for very old emissions reductions undermines the purpose of the contemporaneity requirement by enabling new construction activity to burden the environment with levels of air pollution higher than they have been for many years. The EPA has already given sources a generous 5-year window to aggregate any decreases to net out of review. Since the reduction in actual emissions at the West Plant occurred before the 5-year period, it cannot be used to net out of review.

2. The Baseline for the West Plant Furnaces

Even if the reductions at the West Plant could be deemed to have occurred in 1989, Cyprus still must establish the value of the reductions. In general, this requires a comparison of the emissions levels before and after the reduction. The problem for Cyprus is, of course, the baseline for the West Plant reductions. The EPA policy presumes a calculation based on the 2 years that immediately preceded the change [see 45 FR 52676, 52705, 52718 (1980)]. If EPA uses the 1989 date as the point when the reduction occurred, since the units did not operate during that period, the presumptive baseline is zero and there is no credible reduction. To avoid this result, Cyprus seeks to use a time period well outside the contemporaneous period (July 1975 to June 1977).

As discussed, the Administrator's power to use a different baseline period is limited to those circumstances where the source demonstrates that some time period other than the 2 years that precede the change is more representative of normal source operation. In general, EPA has indicated that this provision is to apply to catastrophic occurrences such as strikes and major industrial accidents (see NSR Workshop Manual, p. A.39). For example, in the WEPCO applicability determination, EPA found the fourth and fifth years prior to the proposed renovation project more representative, since the utility's capacity was greatly reduced after that period due to a cracked steam drum and other severe physical problems (see 57 FR 32323).

On the other hand, EPA has declined to consider a stop in operations, in and of itself, to constitute grounds to change the baseline years. For instance, in the WEPCO rulemaking, EPA adopted a presumption for utilities that considers any 2 years within the 5 years that precede the change to be representative of normal source operations. However, EPA rejected comments seeking to allow further accommodations for units that had been out of operation (see 57 FR 32325):

> The EPA disagrees with comments seeking to allow the use of any 2 consecutive years within the last 5 years of a unit's "operation" rather than within the 5 years directly preceding the proposed change. A shifting of the 5-year period would be difficult to harmonize with definitions of contemporaneous contained in the regulations. This type of open-ended provision would even credit a unit which has been inoperative for 20 or 30 years or longer with a high level of emissions.

Based on these policies, EPA cannot approve either a 1981-1982 baseline or the earlier period put forward by Cyprus. Cyprus has not demonstrated that catastrophic occurrences or other extraordinary circumstances disrupted the West Plant for the entire period between the proposed change and the years Cyprus claims are representative of "normal source operations." Indeed, it is admitted that in the last 10 years the source has been idle due to general economic conditions, and the zero baseline appropriately reflects source utilization under these longstanding market conditions. On the other hand, the very fact that Cyprus seeks to throw out the most recent 13 years suggests that the years Cyprus puts forward are not representative of normal operations in any realistic sense. For these reasons, the baseline for the West Plant furnaces should be zero.

3. Health and Welfare Effects of the Proposed Netting

The PSD regulations restrict the creditability of some decreases in emissions for the purpose of emissions netting. In particular, one provision allows credit for a reduction only to the extent that it has approximately the same qualitative significance for public health and welfare as the increase from the proposed change [see 52.21(b)(3)(vi)(c)]. Where there is reason to believe that the reduction in ambient concentrations from the decrease will not be sufficient to prevent the proposed emissions increase from causing or contributing to a violation of any NAAQS or PSD increment, this provision requires an applicant to demonstrate that the proposed netting transaction (despite the absence of a significant net increase in emissions) will not cause or contribute to such a violation (see 54 FR 27298). Even if EPA found the proffered reductions otherwise quantitatively acceptable in this case--where the existing emissions units have not contributed to ambient concentrations for the last 10 years--Cyprus would have to perform sufficient air quality modeling to demonstrate that the emissions increase from the new units would not violate the applicable NAAQS and PSD increments before the reductions could be credited (see 54 FR 27298).

CONCLUSION

In conclusion, based on the information submitted to date, the proposed 1975 to 1977 baseline period is unacceptable. We are, however, acutely aware of Cyprus' need and concern that their project proceed in a timely manner. To this end, we are willing to work with the Region, the State, and Cyprus to facilitate the resolution of any outstanding permit issues and to assist in the expedited processing of a PSD permit.

ISSUE PAPER RE RESTART OF PINEY POINT

Regulatory Analysis

If the repairs are a modification, a construction permit is required. A modification is a "physical change... which would result in an increase in the actual emissions... [which] shall not include... routine maintenance, repair or replacement..." [62-210.200(185)].

The key issue is whether the repairs are "routine maintenance, repair or replacement." Attorneys on both sides have submitted lengthy analyses on this point, and we have visited the plant, and this appears to be a close enough call that we could justify going either way. If forced to choose, however, we would come down on the side of saying that the repairs are of a routine enough nature that this would not be considered a modification. If EPA were presented with the question, however, they would very likely conclude that the repairs are not routine, but they also would probably say that it's our call.

If the repairs are not routine, then we must address the question as to whether there is an increase in actual emissions. The relevant program is the PSD program (Prevention of Significant Deterioration). For a PSD modification, this question involves comparing emissions on an annual basis and is much more complicated than it appears. Normally, two representative prior years among the last five are averaged to establish a baseline, and the baseline is compared to future allowable, not projected actual, emissions.

In the case of a plant shut down for five years, it is very problematical as to what should be considered to be the baseline emissions. Opponents of the restart have claimed that since additional time has passed and the plant has not operated for five years, the baseline should be zero, but the Department has some discretion in establishing the baseline.

If a PSD construction permit is required, Piney Point will be required to meet BACT (Best Available Control Technology). BACT would almost certainly be determined to equal the presently existing control technology, which is the same control technology existing at other sulfuric acid plants in Florida and the U.S.

xc: CLAIR 3/27

Post-it® Fax Note 7671	Date 3-27 · # of pages ▶ 5
To Howard Rhodes	From Bill Thomas
Co./Dept.	Co. DEP
Phone #	Phone # 813-744-6100
Fax # 904-922-6979	Fax # 813-744-6458

Pros and Cons, From DEP's Standpoint, for Requiring a Construction Permit

Pro (Advantages of Requiring a Construction Permit)

o There appears to be slightly more of a basis in the rules for taking this approach.

(Note: Although it might appear that an advantage is that this is the approach favored by the Manatee County Commissioners, they will probably continue to oppose the restart, so this just delays their opposition until the construction permit stage)

Con (Disadvantages of Requiring a Construction Permit)

o No benefit to the environment; BACT will be the same

o More permitting process for little purpose - end result the same

o Department will probably be sued by Piney Point (they've assured us they'll sue if required to apply for construction permit)

Analysis of Pros and Cons, From Piney Point's Standpoint, of Being Required to Apply for a PSD Construction Permit

The primary reason Piney point is opposed to applying for a construction permit appears to be that they believe that the permitting process itself and the public participation aspects both have the potential to delay the project. Despite their absolute statements that they would sue the Department if required to apply for a construction permit, if we do decide that a construction permit is required, we should point out the following, which may lead them to a business decision to apply for the permit rather than sue:

1) Even without a construction permit, the public will have a point of entry with the Title V permit, which will be required for restart and requires public notice, etc.

2) The PSD permit can be issued and in force relatively quickly, compared to the delays associated with fighting it via the legal process, which they could lose and would have to apply for the PSD permit anyway - much later

Post-it Fax Note 7671	Date 3-27	# of pages 5
To Howard Rhodes	From Bill Thomas	
Co./Dept.	Co. DEP	
Phone #	Phone # SC-744-6100 ext 102	
Fax # 904-922-6979	Fax # 813-744-6458	

3) Consulting costs and permit fees are trivial related to the cost of the project, and probably small related to the legal fees involved in fighting on.

A Caveat

Essentially all the activity to date between the Department and Piney Point has revolved around the restart of the sulfuric acid plant. Other units at the facility will also involve millions of dollars each for repair/renovation. The regulatory situation for these other units is generally, but not exactly, parallel to the situation for the sulfuric acid plant.

WCT 3/26/97
c:\pny397.doc

Post-it® Fax Note 7671	Date 3-27	# of pages ▶ 5
To Howard Rhodes	From Bill Thomas	
Co./Dept.	Co. DEP	
Phone #	Phone # 813-744-6100 ext	

PINEY POINT CONSIDERATIONS

1. The Sulfuric Acid plant has operated at 2000 ton/day, was stack tested and compliance demonstrated May 8, 1990.

2. The key plant equipment related to SO_2 emissions are the sulfur burner and the converter that contains vanadium catalyst to convert SO_2 to SO_3. This equipment is the same as it was in 1990.

3. During normal routine operation, the Sulfuric Acid plant does not cause air pollution problems. Problems occur during improper start-up or a malfunction.

4. Equipment replacement that may be outside the "routine maintenance, repair or replacement" category:

    A. Original acid coolers were National Radiator cast iron sections. The new coolers will be a stainless steel shell and tube heat exchangers.

    B. The new SO_2 absorber is a new design, smaller, different packing and reportedly more efficient.

5. Piney Point has maintained their operating permit, as required by Department rules, for owners who shut a plant down for an extended period, with plans to reactivate the plant at some future time.

Post-it® Fax Note 7671	Date 3-27	# of pages ▶ 5
To Howard Rhodes	From Bill Thomas	
Co./Dept.	Co.	

FDEP SOUTHWEST DIST Fax:813-744-6458 Mar 27 '97 14:25 P.01

Piney Point Phosphates
Sulfuric Acid Plant (EU001) SO_2 Emissions
(as reported in Annual Operating Reports)

YEAR	OPERATING HOURS	TONS H_2SO_4	TONS SO_2
1984	8736	unreported	* 529
1985	0		
1986	0		
1987	0		
1988	3983	246601	179
1989	8760	534979	867
1990	8736	546221	693
1991	unreported	436557	523
1992	3410	72113	142
1993	0		
1994	0		
1995	0		

1500 tons/d Avg

Stack Test Results

DATE	LB SO_2/TON H_2SO_4	TPH H_2SO_4	
20 DEC 83	0.98*	51.00	
1 FEB 84	0.98*	51.00	1224
30 MAR 88	2.01*	65.20	
12 APR 89	3.37	71.75	
5 APR 90	3.01	74.73	1794
8 MAY 90	2.89*	83.50	2004 /day
12 APR 91	2.01	53.70	
25 JUN 91	3.37	65.23	
26 SEP 91	1.44	74.59	
9 APR 92	1.46	61.00	

Note: * in the middle column denotes cases where the reported value was in pounds per hour and conversions were made to calculate the values in the middle and right columns.

Post-it® Fax Note 7671 | Date 3-27 | # of pages 5
To Howard Rhodes | From Bill Thomas
Co./Dept. | Co.