Leslie

From: Pitre, Randy [mailto:Pitre.Randy@epa.gov]
Sent: Thursday, March 21, 2013 9:05 AM
To: Nolting, Leslie R
Cc: Bartley, Richard; Robinson, Jeffrey
Subject: RE: El Paso Natural Gas Company's Laguna Compressor Station

Leslie,

Your request for an additional week to complete the EPA Region 6 request for information is authorized.

Randy L. Pitre
Air Permits Section
U.S. EPA Region 6
Office: (214) 665-7299

From: Nolting, Leslie R [mailto:Leslie_Nolting@KinderMorgan.com]
Sent: Wednesday, March 20, 2013 4:49 PM
To: Pitre, Randy
Subject: RE: El Paso Natural Gas Company's Laguna Compressor Station

Good afternoon Randy,

We are compiling this information as quickly as we can, but respectfully request one more week to provide a complete response by March 29, 2013. Please let me know if this will be acceptable, thank you!

Leslie

From: Pitre, Randy [mailto:Pitre.Randy@epa.gov]
Sent: Tuesday, February 26, 2013 1:37 PM
To: Nolting, Leslie R
Cc: Bartley, Richard; Robinson, Jeffrey
Subject: El Paso Natural Gas Company's Laguna Compressor Station

Document
Number: 14
02/26/2013

Ms. Nolting :

As a follow-up to our conference call on February 21, 2013, please provide responses to the following items:

(1) Please provide a list of the participants (and their titles) who were representing El Paso Natural Gas Company during the February 21, 2013 conference call;

(2) Please review and update the information submitted in El Paso Natural Gas Company's application, dated September 11, 2008, for the renewal of the Title V permit for the Laguna Compressor Station; specifically, the Table 4.1 List of Insignificant Activities, the revised Applicability of Determination for NSPS and MACT requirements, and changes to the General Information and Summary Portion. Additionally, please note that the serial number for AUX A-02 Engine in the application is the same serial number as the AUX A-01 Engine; therefore please verify these serial numbers.

(3) Please provide a more detailed description of the "delivery meters" referenced in your email, dated February 19, 2013; including; (a) provide the number and location (in terms of distance from the Laguna compressor station as well as whether the meter is on tribal land) of the delivery meters between the Bluewater and Laguna compressor stations as well as those between the Laguna and Belen compressor stations; and (b) for each delivery meter, describe the frequency and amount of natural gas delivered, who receives the deliveries, and whether any of the deliveries are (or have the potential to be) received by any Kinder Morgan company or any of its affliates.

No correction is needed to our original response.

7. *A description of operations at the Laguna Compressor Station facility. Where does the natural gas from the Laguna Compressor Station move to next in the natural gas pipeline?*

No correction is needed to our original response.

Thank you again for your work on our permit. We look forward to hearing from you.

Sincerely,

Leslie Nolting
Kinder Morgan, Inc.
Air Compliance - West
(719) 520-4652 (office)
(719) 355-9416 (cell)
(719) 667-7757 (fax)
Leslie_Nolting@KinderMorgan.com

"No trees were harmed in the sending of this email; however, a large number of electrons were terribly inconvenienced."

From: Pitre, Randy [mailto:Pitre.Randy@epa.gov]
Sent: Tuesday, April 02, 2013 11:41 AM
To: Nolting, Leslie R
Cc: Bartley, Richard; Robinson, Jeffrey
Subject: RE: El Paso Natural Gas Company's Laguna Compressor Station

Leslie,

Please advise how much additional time may be required for the information concerning question No. 5.

Randy L. Pitre
Air Permits Section
U.S. EPA Region 6
Office: (214) 665-7299

From: Nolting, Leslie R [mailto:Leslie_Nolting@KinderMorgan.com]
Sent: Friday, March 29, 2013 4:43 PM
To: Pitre, Randy
Cc: Bartley, Richard; Robinson, Jeffrey
Subject: RE: El Paso Natural Gas Company's Laguna Compressor Station

Good afternoon Randy,

Our responses to the items listed below are attached. We are requesting some additional time for the answer to #5 as Kinder Morgan (the parent company of EPNG) operates other business entities in the San Juan Basin unrelated to EPNG and we are in the process of getting some further clarification on these operations.

Thank you for your assistance,

Cedar or any Kinder Morgan company. On this map, Red Cedar interconnects with EPNG at the outlet of the Arkansas Loop plant in the center of the system.

We are also attaching a map (filename "KM Natural Gas Pipelines.pdf") that shows the relative location of Red Cedar's system (in red) to EPNG (purple) and Transcolorado (blue).

We are also attaching a map of the Cortez Pipeline ("Cortez Pipeline Map.pdf), owned and operated by Kinder Morgan CO_2 Company, L.P. Again, these operations are completely unrelated to EPNG or other Kinder Morgan natural gas operations.

2. *For each field operation and production field component identified on the above referenced map, confirm El Paso Natural Gas Company's ownership or operational interest (or indicate the name and address of the owner and/or operator of those operations or components for which El Paso Natural Gas Company does not have any interest) and provide the Standard Industrial Classification (SIC) Code.*

Our original response was correct in that EPNG does not have any ownership or operational interest in field operation or production field components in the San Juan Basin. We can add, however, that the owner/operator of the Red Cedar components are: Red Cedar Gathering Company, 125 Mercado Street, Suite 201, Durango, CO 81301. The SIC Code is 1311.

3. *A simple process flow diagram of the gas flow among the field components identified on the above referenced map.*

{ATTACHED AS Natural Gas PFD.pptx}

4. *A description of the operations associated with each production facility on the above referenced map.*

Red Cedar's gathering pipelines collect gas from multiple wellheads in the gas field. Gas is collected into common pipes leading to treating plants and system outlet points.

Red Cedar's three treating facilities (including Arkansas Loop and Coyote Treating Plants) consist of carbon dioxide (CO_2) removal via amine units and water removal via triethylene glycol dehydrators. After treatment, the gas is considered "pipeline quality."

Gathering compression takes place in various locations throughout the Red Cedar's gathering system (e.g., Bondad and Coyote Compressor Stations. In general, it is the process of boosting the gas pressure in the pipeline from wellhead pressure (<100 psi) to pipeline pressure (>1000 psi).

5. *A description of how the pipeline gathering systems that serve the Laguna Compressor Station are utilized. Are they exclusive to El Paso Natural Gas Company? Or are they a shared resource with other companies? Is natural gas from the gathering pipeline transferred to other third party compressor stations? Are there any gathering pipelines used exclusively by El Paso Natural Gas Company?*

Our initial response was correct in that no pipeline gathering system specifically serves Laguna Compressor Station. However, EPNG does receive gas from Red Cedar (as we noted in our original response), as does TransColorado, and as do other transmission lines. Red Cedar is not exclusively served by either EPNG or TransColorado. Indeed, the majority (approximately 75%) of the gas in Red Cedar's gathering system is sent to transmission lines and local distribution companies (LDCs) that are owned and operated by third-parties completely unaffiliated with EPNG or any other Kinder Morgan company.

6. *Operational agreements between El Paso Natural Gas Company and other gas production and gathering companies that are relevant to or discuss the Laguna Compressor Station.*

Pitre, Randy

From: Nolting, Leslie R <Leslie_Nolting@KinderMorgan.com>
Sent: Tuesday, February 19, 2013 11:03 AM
To: Pitre, Randy
Cc: Duarte, Ricardo (Richard)
Subject: RE: Laguna Compressor Station
Attachments: Transcolorado in NM.pdf

Document
Number 12
02/19/2013

Good morning Randy, our responses are inserted into your email below. Regarding a conference call, would Thursday, February 21 at 2:30 p.m. MST work for you? Let me know and I will send out an Outlook appointment.

Thank you,
Leslie Nolting
719-520-4652

From: Pitre.Randy@epamail.epa.gov [mailto:Pitre.Randy@epamail.epa.gov]
Sent: Thursday, January 17, 2013 8:04 AM
To: Nolting, Leslie R
Subject: Laguna Compressor Station

Ms. Nolting,

Concerning the December 19, 1012 response from El Paso Natural Gas Company concerning the EPA Region 6 request for additional information dated October 25, 2012, to determine the pollutant-emitting activities which comprise the stationary source which includes the Laguna Compressor Station. We have identified several additional questions which will assist EPA in completing the source determination for the Laguna Compressor Station. Please advise of your response to the following questions:

1. Please confirm that the El Paso Natural Gas Bluewater Compressor Station is the only source of natural gas received at the Laguna Compressor Station, and there is no other potential sources of natural gas that could be routed to the Laguna Compressor Station. ***[LN comment]*** The pipeline is configured such that gas can flow in both directions, from Bluewater to Laguna to Belen, or from Belen to Laguna to Bluewater. Historically, the demand has been for flow from west to east sine the 1990's. Between these compressor stations there are currently delivery meters (i.e., points where gas can exit the pipe) but no gas is currently received between these 3 stations.

2. Please confirm that the Laguna Compressor Station only routes the natural gas it receives and compresses to the Belen Compressor Station, and that there are no other potential routes for such gas. ***[LN comment]*** Same as above, the pipeline design allows the gas to go from Laguna to either Bluewater or Belen Stations.

3. What is the extent of the TransColorado Pipeline System that extends through New Mexico? Does the TransColorado Pipeline System connect to the El Paso Natural Gas Company Pipeline System in New Mexico? ***[LN comment]*** A map of the TransColorado system in New Mexico is attached. There are two interconnects with EPNG's system at the Blanco hub, upstream of Bluewater Compressor Station (or downstream, as the case may be), which can either receive gas from or deliver gas to EPNG's system. TransColorado does not own or operate any production facilities in the San Juan Basin. Please note that the TransColorado system was built as a separate pipeline and was under separate ownership until the acquisition of EPNG by Kinder Morgan, Inc. in May, 2012.

We recommend scheduling a conference call to discuss the responses presented after you reply to these questions. Therefore, please advise of an appropriate date and time for a conference call with EPA Region 6 Legal Counsel and Permit Staff.

Randy L. Pitre
Air Permits Section

U.S. EPA Region 6
14455 Ross Avenue
Suite 1200, 6 PD-R
Dallas, Texas 75202-2733
Office: (214) 665-7299

Document Number 11
01/17/2013

Laguna Compressor Station
Randy Pitre to: Nolting, Leslie R)1/17/2013 09:04 AM
Bcc: Richard Bartley, Jeffrey Robinson

From:	Randy Pitre/R6/USEPA/US
To:	"Nolting, Leslie R" <Leslie.Nolting@ElPaso.com>
Bcc:	Richard Bartley/R6/USEPA/US@EPA, Jeffrey Robinson/R6/USEPA/US@EPA

Ms. Nolting,

Concerning the December 19, 1012 response from El Paso Natural Gas Company concerning the EPA Region 6 request for additional information dated October 25, 2012, to determine the pollutant-emitting activities which comprise the stationary source which includes the Laguna Compressor Station. We have identified several additional questions which will assist EPA in completing the source determination for the Laguna Compressor Station. Please advise of your response to the following questions:

1. Please confirm that the El Paso Natural Gas Bluewater Compressor Station is the only source of natural gas received at the Laguna Compressor Station, and there is no other potential sources of natural gas that could be routed to the Laguna Compressor Station.

2. Please confirm that the Laguna Compressor Station only routes the natural gas it receives and compresses to the Belen Compressor Station, and that there are no other potential routes for such gas.

3. What is the extent of the TransColorado Pipeline System that extends through New Mexico? Does the TransColorado Pipeline System connect to the El Paso Natural Gas Company Pipeline System in New Mexico?

We recommend scheduling a conference call to discuss the responses presented after you reply to these questions. Therefore, please advise of an appropriate date and time for a conference call with EPA Region 6 Legal Counsel and Permit Staff.

Randy L. Pitre
Air Permits Section
U.S. EPA Region 6
14455 Ross Avenue
Suite 1200, 6 PD-R
Dallas, Texas 75202-2733
Office: (214) 665-7299

Pitre, Randy

Document Number: 8
07/16/2009

From: Nolting, Leslie R <Leslie_Nolting@kindermorgai
Sent: Tuesday, February 25, 2014 11:49 AM
To: Pitre, Randy
Cc: Duarte, Ricardo (Richard)
Subject: FW: Information request for Laguna Station (per
Attachments: Laguna 1&2 emissions vs fuel.xls

Hi Randy, attached is the second email you requested.

Leslie

From: Nolting, Leslie R
Sent: Thursday, July 16, 2009 9:09 AM
To: 'Penland.Catherine@epamail.epa.gov'
Subject: RE: Information request for Laguna Station (permit R6FOPP71-02)

Hi Cathy,

Laguna units A-01 and A-02 were tested in 1999, and included in the analysis. I have separated out the Laguna unit emission tests into a separate spreadsheet, and plotted the results. As you can see, these tests were conducted at 3 different loads, and the maximum emission rate measured during the tests was 139.58 lb/hr for unit A-02 operating at full load. This is the value that we used as the basis of our NOx PTE for all 3 units (139.58 lb/hr * 8760 hrs/yr * ton/2000 lb = 611 tons/yr).

This data also indicates a maximum heat input during the tests of 26.3 MMBtu/hr based on a fuel higher heating value (HHV) of 1019 Btu/scf.

In the attached spreadsheet in Column M, I back-calculated a brake-specific fuel consumption or BSFC (in Btu/bhp-hr) based on a fuel HHV of 1019 Btu/scf. As you can see, all of the calculated BSFCs are higher than the nominal manufacturer's design specification of 7000 Btu/hp-hr. Please understand that the *manufacturer's design data do not represent a guarantee of engine performance under all operating conditions.* The manufacturer does recognize that operating the unit at lower loads also tends to increase the BSFC (note the manufacturer estimates 9900 Btu/bhp-hr at 50% load).

Our approach to estimating PTE has always been to utilize the best available data to estimate a worst-case hourly emission rate, which is why we used 139.58 lb/hr as our NOx PTE. Looking at the emission test data for unit 2, *there is no reason to believe that this value is outside of the normal operating range of this unit, and no reason to believe that the other two identical units would not be capable of operating in the same fashion and having similar emission rates.*

Regarding the heat input that we specified for these units (33.26 MMBtu/hr), we understand that the 40% safety factor over the manufacturer's rated BSFC at full load may be overly conservative. But again, we want to consider the full operating envelope and determine a high-end value when estimating our PTE for those pollutants that we estimate using AP-42 emission factors (VOC, SO2, and PM). Again, the highest heat input measured during the 1999 emission tests was 26.3 MMBtu/hr. Our estimate of 33.26 MMBtu/hr would be 26% higher than this measured value.

We also have additional operating data for these units, the highest of which indicates a monthly average heat input of 27.9 MMBtu/hr which is based on the <u>lower</u> heating value (LHV) of the fuel. Our estimate of 33.26 MMBtu/hr would be less than 20% higher than this measured value, which we believe is a reasonable margin of safety.

I hope this information is helpful, please let me know if you need anything further.

Leslie

From: Penland.Catherine@epamail.epa.gov [mailto:Penland.Catherine@epamail.epa.gov]
Sent: Friday, July 10, 2009 1:07 PM
To: Nolting, Leslie R
Subject: RE: Information request for Laguna Station (permit R6FOPP71-02)

Leslie,

With respect to the attached folder Laguna EF backup documentation.pdf and your reference to it, I could not tell if the engines at Laguna had been tested and included or not. Could you please clarify this, and if tested - identify which data points in this compilation equate to the engines at Laguna.

Also, in addition to the rationale for safety factor in calculation of heat input rate, fuel use, and emissions for the IC engines, could you please confirm my understanding of your comment on the manufacture design heat input rate. I understand that you said the manufacturer cannot gurantee the design heat input rate for these engines.

Thank you,

Cathy

Catherine G. Penland
EPA Region 6 - 6PD-R
Phone: (214) 665-7122
Fax: (214) 665-6762
penland.catherine@epa.gov

RE: Information request for Laguna Station (permit R6FOPP71-02)

Nolting, Leslie R to: Catherine Penland 07/09/2009 03:06 PM

Cc: "Duarte, Ricardo (Richard)"

Hi Cathy,

This email contains our responses to your information requests for the subject permit. The three bullet items below address your three requests.

- Your first request was by phone on June 26, 2009 in which you indicated that there was a discrepancy in the heat rates between the initial application (which stated that the heat rates for the Clarks was listed as 8.65 MMBtu/hr) and the renewal application (which lists the heat rates for the Clarks as 33.26 MMBtu/hr). We agree that the initial application lists the heat rates as 8.65 MMBtu/hr; but this was clearly a computational error and was corrected in a subsequent submittal dated July 17, 2003 (copy attached, "20030717 T5 application updates.pdf").

As I mentioned before, we do not have manufacturer's emissions specifications for these engines (in terms of g/hp-hr), as they are 50's vintage. A discussion of the factors that we used to develop our potential-to-emit (PTE) is given within the 3rd bullet item later in this email.

- Your follow-up questions by email on June 26 and our responses are below:

1. The actual status of each of the engines as either rich-burn or lean-burn, as there are major discrepancies in the permitting record between what was sent in the application and what is in the permitting file. There are also discrepancies in the fee filing forms over the years, from year to year. Please verify from manufacturer what status each is, as the applicability determination under the MACT ZZZZ does make a difference for both.

Response: The Clark engines (A-01 through A-03) are 2-stroke lean-burn engines. The Ingersolls (AUX A-01 and AUX A-02) are 4-stroke rich burn engines. As we indicated in our renewal application, and in our December 10, 2004 notification to your office of MACT applicability, the Ingersolls are indeed affected units under the RICE MACT. We would be happy to address any specific discrepancies in the permitting file or fee filing forms.

2. Have the plant manager check for decals and specific marking plates on the engines that identify them, for manufacturer, model, variation of model, horse power, heat input, serial number, etc. Provide all information from these identification decals and any historical file material from the purchase. We will need this information to match them up with existing EPA tested engines.

Response: The manufacturer's documentation is attached ("LAGUNA_ORIGINAL_SPEC1-3.pdf").

Units A-01 through A-03 are Clark TLA-10, two cycle engines rated at 3400 hp at 300 rpm. The serial numbers are as given in the permit application. The heat input in Btu/bhp-hr (per the manufacturer) is 7000 at full load, 7500 at 75% load, and 9900 at 50% load.

Units AUX A-01 and AUX A-02 are Ingersoll-Rand PSVG-8, four cycle engines rated at 544 hp at 514 rpm. The serial numbers are as given in the permit application. The heat input in Btu/bhp-hr (per the manufacturer) is 8500 at full load, 9100 at 75% load, and 10300 at 50% load.

3. Are the Clark engines 2 or 4-stroke engines? What about the Ingersols?

Response: The Clark engines (A-01 through A-03) are 2-stroke lean-burn engines. The Ingersolls (AUX A-01 and AUX A-02) are 4-stroke rich burn engines.

4. Have there been any major overhauls of any of the engines that would cause a re-rating of the engines? If so when, and what components were involved?

Response: To the best of our knowledge, there have been no changes to the engines that would cause re-rating.

- With regard to your most recent email dated July 1, 2009, I believe the above information addresses some of your concerns. The design rpm at max load is 300 rpm for the Clarks, and 514 rpm for the Ingersoll's.

In developing our PTE calculations for the Clark units for the initial permit application, we looked at emission test data for all the Clark TLA-10's that we have in our western pipelines system. A summary of the data points is attached ("Laguna EF backup documentation.pdf"). In general, our approach has been to use "worst-case" emission rates for our PTE, which is shown on the first page of this document as 139.58 lb/hr NOx (611 tpy assuming 8760 hours of operation) for the Clarks. This is the PTE that we used in our initial application (via an addendum dated December 22, 1999) and in our renewal application. For comparison to the SIP call document, this equates to 18.6 g/hp-hr (assuming the unit is operating at full load at that point).

For the Ingersoll's, we also looked at test data that we had available for all PSVG-8s. We used the maximum lb/hr (27.34 lb/hr) plus a 20% safety factor to determine the NOx PTE (32.8 lb/hr, 143.7 tpy). This equates to 27.35 g/hp-hr at full load.

To determine the "actual" emission rates which are more representative of operations on an annual basis, we use a more average emission factor. This may vary from year to year based on the best data that is available at that time and is representative of how the unit operated that year. For example, in the initial application, we based our 1998 NOx actual emissions for the Clarks on the average emission factor of 22.68122 pounds per 1000 hp-hour (lb/mhp-hr) from the test data, which is equivalent to 10.29 g/hp-hr. The 1999 through 2006 emission inventories used this same emission factor. In 2007, we updated the factor based on recommendations from our Mechanical Testing Group (MTG) that were more representative of actual operation at the facility. In recommending factors, MTG looks at operating loads and speeds and finds the most representative data in our database. In this case, the NOx emission factor was revised to 8.06 g/hp-hr based on test data for an identical unit at another facility.

For the Ingersolls, we used an average NOx emission factor of 38.5821 lb/mhp-hr to estimate the actual annual emissions, which is equivalent to 17.5 g/hp-hr.

We did conduct reference method testing on all the units except unit A-03 for purposes of developing the initial operating permit application in 1999. This testing was conducted for our internal informational purposes. I will attach the results in a separate email (due to file size considerations). Also, bearing in mind that the auxiliary units are RICE MACT affected units, there is additional emissions information that has been submitted to Region 6 in accordance with these rules. Please let me know if you need me to send any additional copies of this emissions information.

I hope this information is helpful; please call or email me if you have any additional questions or concerns.

Sincerely,

Leslie Nolting
El Paso Corporation
Western Pipelines Environmental Department
(719) 520-4652 (office)
(719) 355-9416 (cell)
(719) 667-7757 (fax)
Leslie.Nolting@Elpaso.com

From: Penland.Catherine@epamail.epa.gov [mailto:Penland.Catherine@epamail.epa.gov]
Sent: Wednesday, July 01, 2009 10:01 AM
To: Nolting, Leslie R
Cc: Robinson.Jeffrey@epamail.epa.gov; Bartley.Richard@epamail.epa.gov
Subject: RE: Information request for Laguna Station (permit R6FOPP71-02)

Leslie,

Am working through the application now, and need a little more info on the Clark engines. I need the design rpm at max load, which is usually posted in the description of engines in the Statement of Basis. This too, should be on one of the identifying decals or plates on the engine, and is generally listed in the application for identifying the performance of the engine. The only thing I've found in the enforcement docs is a reference to the fact that they are turbocharged.

Just to let you know, I am on looking over general information on the Clark engines, and have a fairly good amount of information on these engines, with max. uncontrolled emissions from a response doc to the Phase II NOx SIP Call Rulemaking EPA did in 2004. There were 16 data points for the Clark TVA-10, and a lot of industry reports on general engine emissions which tended to build a fairly average range, dependant on add-ons and inherent features. I'm attaching this doc for your review, as this is what I will be comparing your PTEs to. I can find no information in the file on testing of the engines at this site. References to testing of "similar" engines are going to have to be quantified to compare to this document. Please note that the second comment and clarifications of quantification to engines to the document was received from El Paso Corp., which I assume is the parent Co. for your operations. Please provide your PTE for the Clark and Ingersol engines in the units mentioned in this attached document for direct comparison.

I've also spoken to our expert on IC engines for the MACT rules, and she has checked with manufacturers to verify the status of older rich burn engines (the issue with whether the Clarks and Ingersols are rich burn or lean burn). Information proved noted all naturally aspirated, four-cycle SI engines and *some* turbocharged, four-cycle *SI* engines are rich-burn engines. All other engines, including all two-cycle SI engines and all CI engines, are lean-burn engines. As such, the Clarks appear to be lean burn, as 2-cycle, and you will have to verify the status of the Ingersols. Please keep in mind the MACT ZZZZ implications.

Please let me know if any of these Clark or Ingersol engines at this site have ever been tested and emissions recorded. If so, please provide information on dates, times, test method, and results. I have found the enforcement files with the maintenance records on the Clark engines since the Title V was issued, so I can pretty much see what components of those engines have been replaced during that time frame. Please verify any similar docs before the Title V issuance for the Clarks, and similar docs for the Ingersols for their entire operation at this site.

Please have this and the previously requested info to me by COB 7/9/09, as we are on a very tight time-frame to get permits to public notice, and we need lead time to discuss the changes with you.

Thank you,

Cathy

Catherine G. Penland
EPA Region 6 - 6PD-R
Phone: (214) 665-7122
Fax: (214) 665-6762
penland.catherine@epa.gov

RE: Information request for Laguna Station (permit R6FOPP71-02)

Nolting, Leslie R to: Catherine Penland 06/30/2009 04:40 PM

Hi Catherine,

I am working on this info. Just a head's up, we will not have manufacturer's emissions specifications for these engines (as they were manufactured before emissions were of concern!). We have typically based our PTE on a collection of emissions data that we have at other facilities, but I'll provide you with a detailed description of our estimates with my response.

Thanks,
Leslie

Document
Number: 7
07/09/2009

RE: Information request [illegible] FOPP71-02)
Nolting, Leslie R to: Cathe[illegible] 07/09/2009 03:09 PM
Cc: "Duarte, Ricardo (Richard)"

Hi Cathy, I believe I missed one item.

Regarding the review of the maintenance records, we have not made any changes to the engines that would not qualify as routine maintenance, repair, or replacement; or that would otherwise require permitting or trigger any additional regulatory applicability. As a part of our annual compliance certification, we review any changes at the facility that would have triggered any applicable requirements. Maintenance records for Title V purposes are only required to go back 5 years.

I think I've covered everything... but please let me know if there's anything additional. Thanks again,

Leslie

From: Penland.Catherine@epamail.epa.gov [mailto:Penland.Catherine@epamail.epa.gov]
Sent: Wednesday, July 01, 2009 10:01 AM
To: Nolting, Leslie R
Cc: Robinson.Jeffrey@epamail.epa.gov; Bartley.Richard@epamail.epa.gov
Subject: RE: Information request for Laguna Station (permit R6FOPP71-02)

Leslie,

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Just to let you know, I am on looking over general information on the Clark engines, and have a fairly good amount of information on these engines, with max. uncontrolled emissions from a response doc to the Phase II NOx SIP Call Rulemaking EPA did in 2004. There were 16 data points for the Clark TVA-10, and a lot of industry reports on general engine emissions which tended to build a fairly average range, dependant on add-ons and inherent features. I'm attaching this doc for your review, as this is what I will be comparing your PTEs to. I can find no information in the file on testing of the engines at this site. References to testing of "similar" engines are going to have to be quantified to compare to this document. Please note that the second comment and clarifications of quantification to engines to the document was received from El Paso Corp., which I assume is the parent Co. for your operations. Please provide your PTE for the Clark and Ingersol engines in the units mentioned in this attached document for direct comparison.

I've also spoken to our expert on IC engines for the MACT rules, and she has checked with manufacturers to verify the status of older rich burn engines (the issue with whether the Clarks and Ingersols are rich burn or lean burn). Information proved noted all naturally aspirated, four-cycle SI engines and *some* turbocharged, four-cycle *SI* engines are rich-burn engines. All other engines, including all two-cycle SI engines and all CI engines, are lean-burn engines. As such, the Clarks appear to be lean burn, as 2-cycle, and you will have to verify the status of the Ingersols. Please keep in mind the MACT ZZZZ implications.

NOV 0 7 2008

Document
Number: 5
11/07/2008

Mr. Richard Duarte
Principal Environmental Representative
El Paso Natural Gas Company
Laguna Compressor Station
3801 Atrisco Boulevard, N.W.
Albuquerque, New Mexico 87120

RE: Application package for El Paso Natural Gas Company
Laguna Compressor Station Title V Permit Renewal
Permit Number R6FOPP71-02

Dear Mr. Duarte:

The Environmental Protection Agency received your application on September 12, 2008, and requested additional information on November 3, 2008. The Region has determined that the additional requested information, along with the information submitted in the application, is administratively complete to process the requested operating permit renewal. Therefore, this application is ruled complete on November 6, 2008.

If the Region determines that additional information is necessary to evaluate the application or to take final action, it may request such information in writing and set a reasonable deadline for response. If you have any questions, please contact me at (214) 665-6435 or Catherine Penland of my staff at (214) 665-7122.

Sincerely yours,

Originally Signed
by Jeff Robinson

Jeff Robinson
Chief
Air Permits Section

Catherine Penland:cgp:6PD-R:x7122/11/06/08\
El Paso application completeness letter.doc(Penland #1 Disk)

elpaso Natural Gas

October 31, 2008

Document Number: 4
10/31/2008

Jeffrey Robinson
Chief, Air Permits Section
U.S. EPA Region 6
1445 Ross Avenue, Suite 1200
Dallas, TX 75202-2733

Re: Response to Request for Information
Title V Permit Renewal Application
El Paso Natural Gas Company, Laguna Compressor Station
Permit No. R6FOPP71-02

Dear Mr. Robinson:

I am writing in response to your letter dated October 22, 2008 requesting additional information in support of the Title V Permit Renewal Application for El Paso Natural Gas Company's Laguna Compressor Station. The enclosure attached to this letter provides a response to each item requested by USEPA.

Your letter stated that a response to USEPA's request is required by November 3, 2008. We have tried to respond to each request item as best we could, given the very short time frame provided for a response. We are very eager to obtain a determination that this application is both timely and complete, so that El Paso Natural Gas Company may continue to operate the Laguna Compressor Station under the permit application shield provided by 40 C.F.R. 71.7(b).

If you require any further information in order to make this determination, please contact me at (719) 520-4652 or Richard Duarte at (505) 831-7763. We look forward to working with you and your staff.

Sincerely,

Leslie Nolting

Leslie Nolting
Senior Environmental Representative

Enclosure

El Paso Natural Gas
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PO Box 1087 Colorado Springs, CO 80903
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El Paso Natural Gas
Response to USEPA Request for Information
Laguna Compressor Station

The following information has been requested by USEPA. The following is a listing of each item requested along with EPNG's response.

1. With respect to insignificant emissions units:

   a. A specific list of non-exempt insignificant activities, performed at this specific site, with specific rationale and citation to EPA approved regulations/policy/guidance for permitting on Indian lands. Those sources which may be classified under *de minimus* emission levels, as established in the above referenced documents do not need to be listed. Sources classified under any other rationale will need to be identified specifically, and a rationale presented to make a determination of exemption. Please list each unit, with each federal citation and rationale, for applicability to this category of emission units.

   Response:
   Insignificant activities that may be performed at Laguna Station were listed in Table 4-1. Those items noted with a "0*" in the column titled "Est. total # OR # per yr" column are not currently performed at the site. However, EPNG may perform such activities from time to time.

   The insignificant activities that are currently at the site, along with the rationale for their inclusion, are given in the revised Table 4-1 below.

Table 4-1 List of Insignificant Activities (Quantifiable)

No.	Category	Description	Basis for Treatment as Insignificant Activity	Est. Total # OR # per year	RAP (non-HAP)	HAP
1	Compressor Station Operations & Activities	Fugitive VOC emissions from connections, flanges, open-ended lines, valves, and other components	Estimated emissions <2 tpy regulated pollutants, <0.5 tpy HAPs For compressor facilities with 40 or less reciprocating engines and/or turbines, estimated emissions using GRI-HAPCalc v3.0 are less than the de minimis limit. Component estimate is based on GRI-HAPCalc's default estimate for a compressor station (6 turbines and 6 engines), normalized to a per-unit basis. REFER to attached GRI-HAPCalc estimate.	<40 units	x	x

No.	Category	Description	Basis for Treatment as Insignificant Activity	Est. Total # OR # per year	RAP (non-HAP)	HAP
2	Compressor Station Operations & Activities	Emergency Shut Down system and pressure relief valves	Estimated emissions <2 tpy regulated pollutants, <0.5 tpy HAPs	20/yr	x	x
3	Compressor Station Operations & Activities	Blowdown activities (during startup & shutdown)	Estimated emissions <2 tpy regulated pollutants, <0.5 tpy HAPs	50/yr	x	x
5	General Combustion Activities & Equipment	All natural gas-fired pieces of equipment used solely for heating buildings for personal comfort or for producing hot water for personal use	40 C.F.R. 71.5(c)(11)(i)(D)	2	x	x
14	Storage & Distribution	Any emissions unit, operation, or activity that handles or stores a VOC or HAP organic liquid with a vapor pressure less than 1.5 psia.	Estimated emissions <2 tpy regulated pollutants, <0.5 tpy HAPs	3 (eth-ylene glycol)	x	x
16	Storage & Distribution	Diesel and fuel oil storage tanks with capacity of 40,000 gallons or less	Estimated emissions <2 tpy regulated pollutants, <0.5 tpy HAPs	9	x	x
18	Storage & Distribution	Petroleum-based solvent tanks less than 10,000 gallons (solvent with a vapor pressure less than gasoline)	Estimated emissions <2 tpy regulated pollutants, <0.5 tpy HAPs	1	x	x

b. Further detail on the exact methodology used to determine "estimations" for HAPs, listed in Table 4-1, as quantifiable insignificant activities for startup, shutdown, and maintenance emissions.

<u>Response:</u>
Insignificant activities listed in Table 4-1 that are associated with startup, shutdown, and maintenance are items #2 and #3. These activities include venting of natural gas during a planned or emergency facility shutdown, or venting of natural gas during compressor blowdown. These activities result in VOC emissions of less than 2 tpy each. Venting of natural gas during a planned or emergency facility shutdown is estimated to occur no more than 20 times per year, assuming no more than 200,000 scf released per event. Since natural gas at the site has a density of 0.044 lb/scf and a VOC content below 0.5%, this would result in VOC emissions of less than 2 tpy.

20 events/yr * 200,000 scf/event * 0.044 lb/scf * 0.5% VOC / 2,000 lb/ton = 0.43 tons/yr

Likewise, venting of natural gas during compressor blowdown is estimated to occur no more than 50 times per year, assuming no more than 200,000 scf released per event. Since natural gas at the site has a VOC content below 0.5%, this would result in VOC emissions of less than 2 tpy.

50 events/yr * 200,000 scf/event * 0.044 lb/scf * 0.5% VOC / 2,000 lb/ton = 1.1 tons/yr

The HAP emissions from these activities will be well below 0.5 tpy, since the weight percentage of HAPs in the natural gas is negligible. The GRI HAPCalc speciation composition data obtained during a joint American Petroleum Institute (API)/GRI fugitive testing program indicates a HAP content of less than 0.1% by weight for compressor stations.

c. Further detail on the methodology and rationale to determine "quantifiable" for all activities, from item #4 down on Table 4-1, as insignificant activities. Inclusion on an insignificant activities list for a state program is not justification for "quantifiable" on Indian lands. Please quantify these emissions per an approved EPA methodology or test.

Response:
As noted above in the response to #1.a, certain items on the submitted list of insignificant activities are not currently located at the site. These items were listed to cover equipment or activities that EPNG commonly uses at its compressor stations. However, we have narrowed the list of insignificant activities for Laguna Station to include only equipment or activities currently at this facility.

A discussion of each item (#4 down) in Table 4-1 is given below for equipment or activities located at Laguna.

Item 5: Natural gas and/or LPG-fired pieces of equipment
There is a natural gas-fired space heater and a hot water heater at Laguna. These units qualify as insignificant activities based on 40 C.F.R. 71.5(c)(11)(i)(D): "Heating units used for human comfort that do not provide heat for any manufacturing or other industrial process."

Item 14: Storage tanks containing liquids with a vapor pressure < 1.5 psia
There is one ethylene glycol tank at the site. We ran the TANKS 4.0.9d model for a 210-bbl tank containing ethylene glycol (a HAP) with a vapor pressure of 0.0006 psia. We very conservatively assumed one turnover per day. The TANKS printout for Tank "Insig14" is attached. Total emissions are 0.85 lb per year (0.0004 tpy). This type of tank is insignificant for criteria pollutants and HAPs.

Item 16: Diesel and Fuel-oil storage tanks < 40,000 gallons
The following lube oil and diesel fuel tanks are located at Laguna:

Tank	Capacity (gal)
Aux. Lube Oil Tank	8,820
Main Engine Lube Oil	8,820
Diesel Tank	300
Northern-most, Buried Used Oil Tank near East Fence	1,000
Southern-most, Buried Used Oil/Oily water Tank near East Fence	1,000
Eastern-most Used Oil Tank near South fence	734
Western-most used Oil Tank near South Fence	734
Upper-most Used Oil tank at Comp. Bldg	734
Lower-most Used Oil tank at Comp. Bldg	734

As a conservative estimate of maximum emissions from tanks in this category, we ran the TANKS 4.0.9d model for a 40,000 gallon tank containing diesel fuel. We very conservatively assumed one turnover per day. The TANKS printout for Tank "Insig16" is attached. Total VOC emissions for this type of tank were determined to be 77 lb per year, or 0.04 tons/yr. This type of tank is therefore insignificant for criteria pollutants and HAPs.

Item 18: Solvent storage tanks < 10,000 gallons
We ran the TANKS 4.0.9d model for a 10,000 gallon tank containing gasoline with RVP 13.5 with the speciation profile for gasoline reformulated with ethanol. We very conservatively assumed one turnover per month. The TANKS printout for Tank "Insig17" is attached. Total emissions are 3,757 lb per year (1.9 tpy). HAP emissions are well below 0.5 tpy.

Since item 18 specifies a vapor pressure less than gasoline, we can assume that a storage tank containing liquid with a lower vapor pressure would also be an insignificant activity.

Units proposed to be deleted from Table 4-1
The following units are proposed to be deleted from Table 4-1 since they are not currently at the Laguna facility:

Item 4: Cooling towers
Item 6: Oil-fueled heating pieces of equipment
Items 7-9: IC engines and Turbines
Items 10 and 11: Surface Coating

Item 12: Solvent Cleaning Equipment
Item 13: 250-gallon and smaller storage tanks
Item 15: Gasoline dispensing operations
Item 17: Gasoline storage tanks < 10,000 gallons
Item 19: Condensate storage tanks < 105,000 gallons
Items 20-23: Miscellaneous Activities

d. Table 4-2 of Section 4 lists non-quantifiable insignificant activities, without reference to specific emission units at this site, and without rationale for why these emissions cannot be quantified. Please provide the direct link to the emission units being claimed as insignificant emissions, and provide rationale for why these emissions cannot be quantified under any approved EPA methodology, estimation or test. Also, only list non-exempt insignificant emission sources.

Response:
Items in Table 4-2 were intended for informational purposes only, and include items that EPA has designated as "trivial activities" (refer to "White Paper for Streamlined Development of Part 70 Permit Applications", 07/10/95) as well as items that EPA Regions 6 and 9 have approved as "trivial activities" in other states. We understand that EPA has not approved these state lists for use on Indian lands. We would appreciate the opportunity to re-submit the data that these states submitted to get these lists approved by EPA, but cannot complete this within the timeframe requested by this letter. In the interim, since the items that EPA has approved for use on Indian lands as "trivial activities" are not required to be listed in the application, please disregard Table 4-2.

Federally approved lists for insignificant activities for sources on state lands are only applicable to sources on those lands. The federal definition of insignificant, based on a de minimus emission level as established in 40 CFR 71.5(c)(11)(ii)(A) and (B) and Section 112(g) of the CAA, is the only federally approved list for insignificant activities on Indian lands. Source size, beyond federal applicability distinctions, is not an EPA approved category on Indian lands for insignificance or trivial source category. Case-by-case insignificant activities may be proposed to EPA through the Region responsible for the Part 71 permitting program, but the submittal must include enough rationale/methodology/quantification to make a determination of insignificance under federal rules. If the EPA approved methodology to test, quantify or estimate emissions at this site prove emissions are not de minimus under 40 CFR 71 .5(c)(11)(ii)(A) and (B), you will need to amend the application to include these emissions and units in the list of regulated emission units.

Response:
We note this comment, and we hope that we have addressed USEPA's questions regarding insignificant activities with this response.

2. Provide actual emission rates for combustion sources, as confirmed by fuel usage rates under Section D of EPA Form 5900-80, and Annual Emission Fees filed as a condition of the permit, which show variable rates, including reduced rates.

Response:
Annual emissions for 2007, along with supporting calculations based on reported fuel usage and permit fees for these emissions, were provided to USEPA Region 6 in a submittal dated July 17, 2008. A copy of this submittal is provided as an attachment to this letter.

3. Provide specific exemption criteria from each NSPS or MACT, with regulatory citations and rationale for each unit subject or potentially subject to federal regulatory applicability. Statements such as "The facility does not have my equipment or processes that meet the criteria of the above referenced standards" or simply ". . . does not meet the criteria . . ." is not sufficient rationale for exemption, particularly after identifying this source as potentially applicable to these standards.

Response:
A more thorough applicability assessment for each NSPS or MACT that is potentially applicable to equipment at this facility is included below.

NEW SOURCE PERFORMANCE STANDARDS (NSPS, 40 CFR 60)

Boilers (40 CFR 60, Subpart D, Da, Db, and Dc)
These Subparts apply to boilers or process heaters constructed, modified or reconstructed after the rule applicability date. There are no boilers or process heaters at this facility. The significant emissions units at this facility are three main compressor engines (Units A-01, A-02 and A-03) and two auxiliary power engines (Units AUX A-01 and AUX A-02). So, this Subpart does not apply.

Petroleum Liquids (40 CFR 60, Subpart K, Ka, and Kb)
These Subparts apply to tanks at are used for storage of petroleum liquids constructed, modified or reconstructed after the rule applicability date. There are no tanks that are used for storage of petroleum liquids at this facility. So, this Subpart does not apply.

Gas Turbines (40 CFR 60, Subpart GG)
This subpart applies to stationary gas turbines constructed, modified or reconstructed after the rule applicability date. There are no gas turbines at this facility. So, this Subpart does not apply.

Equipment Leaks (40 CFR 60, Subpart KKK)
This subpart applies to equipment located at onshore natural gas processing plants that has been constructed, modified or reconstructed after the rule applicability date. The term "natural gas processing plant" is defined in this Subpart as "any

processing site engaged in the extraction of natural gas liquids from field gas, fractionation of mixed natural gas liquids to natural gas products, or both."

The Laguna facility is a natural gas compressor station and does not perform extraction of natural gas liquids from field gas or fractionation of mixed natural gas liquids to natural gas products. So, this Subpart does not apply.

Sweetening Units (40 CFR 60, Subpart LLL)
This subpart applies to two types of facilities that process natural gas: (1) sweetening units and (2) sweetening units followed by a sulfur recovery unit. A "sweetening unit" is defined in this Subpart as "a process device that separates the H_2S and CO_2 contents from the sour natural gas stream." A "sulfur recovery unit" is defined by this Subpart as "a process device that recovers element sulfur from acid gas."

The Laguna facility does not have a sweetening unit or a sulfur recovery unit. So, this Subpart does not apply.

NATIONAL EMISSIONS STANDARDS FOR HAZARDOUS AIR POLLUTANTS (NESHAP, 40 CFR 61 AND 63)

The NESHAP for asbestos under 40 CFR 61 Subpart M is applicable to this facility only during asbestos demolition or renovation. There is currently an inactive asbestos landfill at the facility. No requirements currently apply.

Source category NESHAP standards for maximum achievable control technology (MACT) have been promulgated under 40 CFR 63 for certain equipment and/or processes that are generally associated with natural gas production and/or transmission facilities. These promulgated MACT standards are as follows:

Oil and Natural Gas Production (40 CFR 63, Subpart HH)
This Subpart applies to equipment located at oil and natural gas production facilities that meet the criteria listed in the rule. According to 40 CFR 63.760, this Subpart applies to sources that are either a major source or area source of HAPs and that perform either of the following operations:

1. Sources that process, upgrade, or store hydrocarbon liquids prior to the point of custody transfer; or

2. Sources that process, upgrade, or store natural gas prior to the point at which natural gas enters the natural gas transmission and storage source category or is delivered to a final end user.

The Laguna Compressor Station does not process, upgrade, or store hydrocarbon liquids. Hydrocarbon liquids are not handled by this site, only hydrocarbon gases.

This facility also does not process, upgrade, or store natural gas. A discussion of each of these terms is included below:

Process

Regarding the term "process," this Subpart contains a definition of "natural gas processing plant." Similar to NSPS Subpart KKK, this Subpart defines "natural gas processing plant" as: "any processing site engaged in the extraction of natural gas liquids from field gas, or the fractionation of mixed NGL to natural gas products, or a combination of both." The Laguna facility is a natural gas compressor station and does not perform extraction of natural gas liquids from field gas or fractionation of mixed natural gas liquids to natural gas products.

Upgrade

The definition of the term "facility" in this Subpart clarifies the meaning of the word "upgrade." This definition states that upgrade means "remove impurities or other constituents to meet contract specifications." The Laguna facility does not upgrade the natural gas compressed at this site, since it does not perform any operations designed to remove impurities or other constituents to meet contract specifications. Only compression of natural gas is performed at the site.

Store

The Laguna facility does not store, or have the capacity to store, any hydrocarbon gases or liquids. There are no storage tanks maintained at the site for such purpose. Natural gas passes through the site via pipeline and no portion of the gas is stored at the site.

Since the Laguna facility does not meet the criteria for an oil and natural gas production facility as listed in this rule, this MACT standard does not apply.

Natural Gas Transmission and Storage (40 CFR 63, Subpart HHH)

This Subpart applies to natural gas transmission and storage facilities that transport or store natural gas prior to entering the pipeline to a local distribution company or to a final end user (if there is no local distribution company), and that are major sources of HAPs.

The Laguna facility does satisfy these criteria. However, 40 CFR 1270(b) states that the "affected source" covered by this Subpart is a glycol dehydration unit. Then, 40 CFR 1270(c) states that a facility that does not contain an affected source is not subject to the requirements of this Subpart.

This subpart defines "Glycol dehydration unit" to be "a device in which a liquid glycol (including, but not limited to, ethylene glycol, diethylene glycol, or triethylene glycol) absorbent directly contacts a natural gas stream and absorbs water in a contact tower or absorption column (absorber). The glycol contacts and absorbs water vapor and other gas stream constituents from the natural gas and becomes "rich" glycol. This glycol is then regenerated in the glycol dehydration unit reboiler. The "lean" glycol is then recycled."

There are no glycol dehydration units at the Laguna facility. Since this facility does not have an affected source (i.e., a glycol dehydration unit), NESHAP Subpart HHH does not apply.

Reciprocating Internal Combustion Engine MACT (Subpart ZZZZ)
This MACT standard only applies to certain types of engines located at major or area sources of HAPs. This facility is a major source of HAPs, as discussed above. There are five engines located at this facility, all of which are greater than 500 brake horsepower, the size cutoff for the MACT standard.

Two of these engines (Units AUX A-01 and AUX A-02) are existing 4-stroke rich-burn (4SRB) engines that are subject to MACT requirements. The other three engines are all existing 2-stroke lean-burn (2SLB) engines that are exempt from MACT requirements, as described in 40 CFR 63.6600(c). The requirements for this MACT that apply to the existing 4SRB engines have been added to the proposed changes to the Title V permit included in Attachment 7.2 of our permit renewal application.

4. Provide an explanation and identification to specific units for the increase from 23 tpy to 36 tpy for Total HAPs, as listed in Section J of EPA Form 5900-79, and specifically the increase in Formaldehyde. Total HAPs are proposed to go above the major source threshold in the Facility Emissions Summary, Section J of EPA Form 5900-79. Identify how much increase is associated with each unit regulated at this site, and if any increase is associated with an unregulated source.

Response:
The increase in emissions of Total HAPs is associated with regulated sources that are listed on the current Title V permit for this facility. It is not due to changes or additions of any unregulated sources. The most significant differences are seen for the three main compressor units, although emissions for the two auxiliary units are also revised slightly.

Potential HAP emissions for the five engines at this site have been estimated using the maximum ratings for each engine and HAP emission factors. Both the maximum ratings for each unit and the emission factors used in the renewal application are different than values used in the original Title V application.

Regarding maximum heat input ratings, the revised ratings represent a better estimate of the maximum operating capability of each engine. These have been calculated using the rated design capacity of each unit and a conservative estimate of the heating value of natural gas.

Regarding emission factors, in the original application for Laguna, EPNG had used factors from HAPCalc, a software package designed by the Gas Research Institute (GRI) for use with oil and gas facilities. In the renewal application, EPNG has used factors from USEPA's AP-42 chapter for natural gas-fired reciprocating engines (Chapter 3.2). These factors were believed to be a more conservative, worst-case representation of the facility's Potential HAP emissions.

None of the revisions in potential emissions of HAPs or criteria pollutants were the result of any modifications at the facility.

TANKS 4.0.9d
Emissions Report - Summary Format
Tank Indentification and Physical Characteristics

Identification

User Identification:	Insig14
City:	Albuquerque
State:	New Mexico
Company:	EPNG
Type of Tank:	Vertical Fixed Roof Tank
Description:	Ethylene glycol storage tank

Tank Dimensions

Shell Height (ft):		15.00
Diameter (ft):		10.00
Liquid Height (ft) :		15.00
Avg. Liquid Height (ft):		7.50
Volume (gallons):		8,812.81
Turnovers:		365.00
Net Throughput(gal/yr):		3,216,675.13
Is Tank Heated (y/n):	N	

Paint Characteristics

Shell Color/Shade:	White/White
Shell Condition	Good
Roof Color/Shade:	White/White
Roof Condition:	Good

Roof Characteristics

Type:	Cone	
Height (ft)		0.00
Slope (ft/ft) (Cone Roof)		0.06

Breather Vent Settings

Vacuum Settings (psig):	-0.03
Pressure Settings (psig)	0.03

Meterological Data used in Emissions Calculations: Albuquerque, New Mexico (Avg Atmospheric Pressure = 12.15 psia)

TANKS 4.0.9d
Emissions Report - Summary Format
Liquid Contents of Storage Tank

Insig14 - Vertical Fixed Roof Tank
Albuquerque, New Mexico

Mixture/Component	Month	Daily Liquid Surf. Temperature (deg F) Avg.	Min.	Max.	Liquid Bulk Temp (deg F)	Vapor Pressure (psia) Avg.	Min.	Max.	Vapor Mol. Weight.	Liquid Mass Fract.	Vapor Mass Fract.	Mol. Weight	Basis for Vapor Pressure Calculations
Ethylene glycol	All	58.54	51.41	65.66	56.17	0.0006	0.0004	0.0010	62.0678			62.07	Option 2: A=8.21211, B=2161.91, C=208.43

TANKS 4.0.9d
Emissions Report - Summary Format
Individual Tank Emission Totals

Emissions Report for: Annual

Insig14 - Vertical Fixed Roof Tank
Albuquerque, New Mexico

	Losses(lbs)		
Components	Working Loss	Breathing Loss	Total Emissions
Ethylene glycol	0.77	0.08	0.85

TANKS 4.0.9d
Emissions Report - Summary Format
Tank Indentification and Physical Characteristics

Identification	
User Identification:	Insig16
City:	Albuquerque
State:	New Mexico
Company:	EPNG
Type of Tank:	Vertical Fixed Roof Tank
Description:	40,000-gallon diesel fuel tank
Tank Dimensions	
Shell Height (ft):	19.00
Diameter (ft):	19.00
Liquid Height (ft) :	19.00
Avg. Liquid Height (ft):	9.50
Volume (gallons):	40,298.04
Turnovers:	365.00
Net Throughput(gal/yr):	14,708,783.14
Is Tank Heated (y/n):	N
Paint Characteristics	
Shell Color/Shade:	White/White
Shell Condition	Good
Roof Color/Shade:	White/White
Roof Condition:	Good
Roof Characteristics	
Type:	Cone
Height (ft)	0.00
Slope (ft/ft) (Cone Roof)	0.06
Breather Vent Settings	
Vacuum Settings (psig):	-0.03
Pressure Settings (psig)	0.03

Meterological Data used in Emissions Calculations: Albuquerque, New Mexico (Avg Atmospheric Pressure = 12.15 psia)

TANKS 4.0.9d
Emissions Report - Summary Format
Liquid Contents of Storage Tank

Insig16 - Vertical Fixed Roof Tank
Albuquerque, New Mexico

Mixture/Component	Month	Daily Liquid Surf. Temperature (deg F)			Liquid Bulk Temp (deg F)	Vapor Pressure (psia)			Vapor Mol. Weight.	Liquid Mass Fract.	Vapor Mass Fract.	Mol. Weight	Basis for Vapor Pressure Calculations
		Avg.	Min.	Max.		Avg.	Min.	Max.					
Distillate fuel oil no. 2	All	58.54	51.41	65.66	56.17	0.0062	0.0048	0.0079	130.0000			188.00	Option 1: VP50 = .0045 VP60 = .0065

TANKS 4.0.9d
Emissions Report - Summary Format
Individual Tank Emission Totals

Emissions Report for: Annual

Insig16 - Vertical Fixed Roof Tank
Albuquerque, New Mexico

	Losses(lbs)		
Components	Working Loss	Breathing Loss	Total Emissions
Distillate fuel oil no. 2	70.33	7.31	77.63

TANKS 4.0.9d
Emissions Report - Summary Format
Tank Indentification and Physical Characteristics

Identification

User Identification:	Insig17	
City:	Albuquerque	
State:	New Mexico	
Company:	EPNG	
Type of Tank:	Vertical Fixed Roof Tank	
Description:	10,000-gallon gasoline tank	

Tank Dimensions

Shell Height (ft):		12.00
Diameter (ft):		12.00
Liquid Height (ft) :		12.00
Avg. Liquid Height (ft):		6.00
Volume (gallons):		10,152.36
Turnovers:		12.00
Net Throughput(gal/yr):		121,828.27
Is Tank Heated (y/n):	N	

Paint Characteristics

Shell Color/Shade:	White/White	
Shell Condition	Good	
Roof Color/Shade:	White/White	
Roof Condition:	Good	

Roof Characteristics

Type:	Cone	
Height (ft)		0.00
Slope (ft/ft) (Cone Roof)		0.06

Breather Vent Settings

Vacuum Settings (psig):		-0.03
Pressure Settings (psig)		0.03

Meterological Data used in Emissions Calculations: Albuquerque, New Mexico (Avg Atmospheric Pressure = 12.15 psia)

TANKS 4.0.9d
Emissions Report - Summary Format
Liquid Contents of Storage Tank

Insig17 - Vertical Fixed Roof Tank
Albuquerque, New Mexico

Mixture/Component	Month	Daily Liquid Surf. Temperature (deg F) Avg.	Min.	Max.	Liquid Bulk Temp (deg F)	Vapor Pressure (psia) Avg.	Min.	Max.	Vapor Mol. Weight.	Liquid Mass Fract.	Vapor Mass Fract.	Mol. Weight	Basis for Vapor Pressure Calculations
Gasoline (RVP 13.5)	All	58.54	51.41	65.66	56.17	7.0507	6.1605	8.0402	62.0000			92.00	Option 4: RVP=13.5, ASTM Slope=3
1,2,4-Trimethylbenzene						0.0193	0.0144	0.0256	120.1900	0.0250	0.0001	120.19	Option 2: A=7.04383, B=1573.267, C=208.56
Benzene						1.1212	0.9158	1.3637	78.1100	0.0180	0.0042	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Cyclohexane						1.1642	0.9554	1.4095	84.1600	0.0024	0.0006	84.16	Option 2: A=6.841, B=1201.53, C=222.65
Ethanol									46.0700	0.0560	0.0000	46.07	
Ethylbenzene						0.1031	0.0800	0.1318	106.1700	0.0140	0.0003	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Hexane (-n)						1.8417	1.5232	2.2130	86.1700	0.0100	0.0039	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Isooctane									114.2200	0.0400	0.0000	114.22	
Isopropyl benzene						0.0455	0.0346	0.0593	120.2000	0.0050	0.0000	120.20	Option 2: A=6.93666, B=1460.793, C=207.78
Toluene						0.3154	0.2512	0.3929	92.1300	0.0700	0.0046	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Unidentified Components						10.6362	10.6101	10.6101	61.7266	0.6896	0.9849	96.74	
Xylene (-m)						0.0858	0.0664	0.1100	106.1700	0.0700	0.0013	106.17	Option 2: A=7.009, B=1462.266, C=215.11

TANKS 4.0.9d
Emissions Report - Summary Format
Individual Tank Emission Totals

Emissions Report for: Annual

Insig17 - Vertical Fixed Roof Tank
Albuquerque, New Mexico

	Losses(lbs)		
Components	Working Loss	Breathing Loss	Total Emissions
Gasoline (RVP 13.5)	1,268.02	2,488.70	3,756.72
Hexane (-n)	4.91	9.65	14.56
Benzene	5.39	10.57	15.96
Isooctane	0.00	0.00	0.00
Toluene	5.89	11.56	17.45
Ethylbenzene	0.39	0.76	1.14
Xylene (-m)	1.60	3.15	4.75
Isopropyl benzene	0.06	0.12	0.18
1,2,4-Trimethylbenzene	0.13	0.25	0.38
Cyclohexane	0.75	1.46	2.21
Ethanol	0.00	0.00	0.00
Unidentified Components	1,248.90	2,451.18	3,700.08

OCT 2 2 2008

Document Number: 3 10/22/2008

Richard Duarte
Principal Environmental Representative
El Paso Natural Gas Co., Laguna Compressor Station
3801 Atrisco Blvd., NW
Albuquerque, New Mexico 87120

Re: Application package for El Paso Natural Gas Company
Laguna Compressor Station Title V Permit Renewal
Permit No. R6FOPP71-02

Dear Mr. Duarte,

This letter acknowledges receipt of the permit application for the renewal of the Title V air operating permit for the El Paso Natural Gas Company (EPNG), Laguna Compressor Station. The United States Environmental Protection Agency (EPA), Region 6 received your application on September 12, 2008, and assigned it Operating Permit Number R6NM-02-09R1, which when issued, will replace the current Operating Permit Number R6FOPP71-02.

The information submitted in the application has been reviewed and determined insufficient to process the requested renewal application. In order to avoid a finding of incompleteness under 40 CFR 71.5(a)(2), you must provide the following information no later than November 3, 2008.

1. With respect to insignificant emissions units:

   a. A specific list of non-exempt insignificant activities, performed at this specific site, with specific rationale and citation to EPA approved regulations/policy/guidance for permitting on Indian lands. Those sources which may be classified under *de minimus* emission levels, as established in the above referenced documents do not need to be listed. Sources classified under any other rationale will need to be identified specifically, and a rationale presented to make a determination of exemption. Please list each unit, with each federal citation and rationale, for applicability to this category of emission units.
   b. Further detail on the exact methodology used to determine "estimations" for HAPs, listed in Table 4-1, as quantifiable insignificant activities for startup, shutdown, and maintenance emissions.
   c. Further detail on the methodology and rationale to determine "quantifiable" for all activities, from item #4 down on Table 4-1, as insignificant activities. Inclusion on an insignificant activities list for a state program is not justification for "quantifiable" on Indian lands. Please quantify these emissions per an approved EPA methodology or test.

d. Table 4-2 of Section 4 lists non-quantifiable insignificant activities, without reference to specific emission units at this site, and without rationale for why these emissions cannot be quantified. Please provide the direct link to the emission units being claimed as insignificant emissions, and provide rationale for why these emissions cannot be quantified under any approved EPA methodology, estimation or test. Also, only list non-exempt insignificant emission sources.

Federally approved lists for insignificant activities for sources on state lands are only applicable to sources on those lands. The federal definition of insignificant, based on a de minimus emission level, as established in 40 CFR 71.5(c)(11)(ii)(A) and (B) and Section 112(g) of the CAA, is the only federally approved list for insignificant activities on Indian lands. Source size, beyond federal applicability distinctions, is not an EPA approved category on Indian lands for insignificance or trivial source category. Case-by-case insignificant activities may be proposed to EPA through the Region responsible for the Part 71 permitting program, but the submittal must include enough rational/methodology/quantification to make a determination of insignificance under federal rules. If the EPA approved methodology to test, quantify or estimate emissions at this site prove emissions are not *de minimus* under 40 CFR 71.5(c)(11)(ii)(A) and (B), you will need to amend the application to include these emissions and units in the list of regulated emission units.

2. Provide actual emission rates for combustion sources, as confirmed by fuel usage rates under Section D of EPA Form 5900-80, and Annual Emission Fees filed as a condition of the permit, which show variable rates, including reduced rates.

3. Provide specific exemption criteria from each NSPS or MACT, with regulatory citations and rationale for each unit subject or potentially subject to federal regulatory applicability. Statements such as "The facility does not have any equipment or processes that meet the criteria of the above referenced standards" or simply ". . . does not meet the criteria . . ." is not sufficient rationale for exemption, particularly after identifying this source as potentially applicable to these standards.

4. Provide an explanation and identification to specific units for the increase from 23 tpy to 36 tpy for Total HAPs, as listed in Section J of EPA Form 5900-79, and specifically the increase in Formaldehyde. Total HAPs are proposed to go above the major source threshold in the Facility Emissions Summary, Section J of EPA Form 5900-79. Identify how much increase is associated with each unit regulated at this site, and if any increase is associated with an unregulated source.

Section 6 of the application discusses your facilities' off-permit changes. EPA does not accept any kind of "like-kind" replacement as unqualified routine maintenance or repair. Like-kind replacement does not extend to replacement of an entire unit, except with respect to "replacement" under the Prevention of Significant Deterioration Rules under 40 CFR 52.21. The September 9, 1988 Memo from Don R. Clay, *"Applicability of Prevention of Significant Deterioration (PSD) and New Source Performance Standards (NSPS) to the Wisconsin Electric Power Company (WEPCO) Port Washington Life Extension Project"*, and the 1990 letter from William G. Rosenberg to John Boston, President of WEPCO, which act as EPA guidance on this subject, are attached for your information.

EPA regards these like-kind replacements as modifications that need to be evaluated to determine if there would be a significant net emissions increase like any other physical or operational change at the site. If PSD applicability is triggered for any of these "replacements," you may need to apply for a PSD permit to construct, or provide a netting analysis to demonstrate insignificant net emissions increase under those rules. If the replacement emissions increase is PSD significant, you will be subject to the full applicable requirements listed under 40 CFR § 71.2.

If the Region determines that additional information is necessary to evaluate the application or to take final action, it may request such information in writing and set a reasonable deadline for response. If you have any questions, please contact me at (214) 665-6435 or Catherine Penland of my staff at (214) 665-7122.

Sincerely yours,

Originally Signed
by Jeff Robinson

Jeffrey Robinson
Chief, Air Permits Section

Enclosures

Catherine Penland:cgp:10/21/08:El Paso Nat. Gas Co. Laguna compressor stat. nonsufficiency letter.doc

6PD-R	6RC-M
Johnston	Bartley

MEMORANDUM

DATE: September 9, 1988

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 variouspollutants 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 facilityis "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 tothe 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.

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

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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.

of these was 16 inches in 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 to any federally enforceable

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2The 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. 3The 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.

limit) without having to obtain a PSD permit. Thus, emissions increases at Port Washington associated with increased opera- tions 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.

4The 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 priorto 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.

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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.l4(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 toaccommodate 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 unitwhich 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 tocombust 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

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
WASHINGTON D.C.20460

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

Dear Mr. Boston:

On January 19, 1990, the United States Court of Appeals for the Seventh Circuit in Wisconsin Electric Power Co. v. Reilly, Nos. 88-3264 and 89-1339, issued its decision regarding a challenge by Wisconsin Electric Power Company (WEPCO) to two final determinations issued by the Environmental Protection Agency (EPA). In these determinations, EPA concluded that WEPCO's proposed renovations to its Port Washington power plant would be subject to new source performance standards (NSPS) and prevention of significant deterioration (PSD) requirements.

In its decision, the court upheld all but one of the positions advanced by EPA in the NSPS and PSD applicability determinations. However, the court rejected EPA's position on the issue of whether the "actual-to-potential" method--referred to by the court as the "potential to emit concept"--should be used to calculate emissions increases for PSD purposes in this case. Consequently, the Seventh Circuit vacated and remanded the PSD determination to EPA for further action consistent with the court's decision.

As you know, EPA decided to acquiesce in the court's holding rather than seek rehearing. This letter constitutes EPA's revised PSD applicability determination in response to the court's remand order.

The Agency believes that the court's principal instruction--that EPA consider past operating conditions at the plant when addressing modifications that involve "like-kind replacements"--can be reasonably accommodated within the present regulatory framework without further litigation in this case. The net result of the court's ruling is the recognition of a subcategory of "like- kind replacements" under the "major modification" definition of EPA's new source review provisions.

As explained below, EPA will employ an "actual-to-actual" method to calculate emissions increases for WEPCO's proposed renovations to its Port Washington power plant. The outcome in this case is that WEPCO wil l not be subject to PSD review for sulfur dioxide (S02), particulate matter (PM), carbon monoxide, or hydrocarbons. However, there will be a significant net increase in actual emissions of nitrogen oxides (NOx), and WEPCO must obtain a PSD permit for that pollutant.

I. BACKGROUND

A. Factual Background.

The WEPCO owns and operates five coal-fired, steam-generating units at its Port Washington facility near Milwaukee. All units had an original design capacity of 80 megawatts when they were placed in service between 1935 and 1950. However, due to age-related deterioration and loss of efficiency, both the physical capability and actual utilization of the plant have declined over time. Unit 5 was shut down completely due to a cracked rear steam drum. Consequently, by 1987, WEPCO was faced with removing the units from service as they reached their planned retirement dates beginning in the early 1990's, unless it undertook a costly "life extension" program to restore the physical and economic viability of the units and extend their useful life for approximately 20 years. The WEPCO proposed such a life extension to include replacement of the steam drums, air heaters, and other major capital improvements totaling over $80 million. It should be noted that this program is not a pollution control project (i.e., it is not intended to add on or improve pollution control systems even though modest improvements to the particulate matter control devices are a part of the program).

In a series of applicability determinations in 1988 and 1989, EPA ruled that the renovations planned under WEPCO's life extension program would constitute a "modification" for purposes of the NSPS provisions of the Clean Air Act (Act), and a "major modification" under the PSD provisions of the Act. Thus, WEPCO would have had to install some level of control equipment or physical capacity restriction to avoid NSPS coverage for three of the five units proposed to be renovated. As to PSD, the company would have had to accept operational restrictions or lower emissions rates to "net out" of review. Regarding SO2, for example, WEPCO could have almost doubled its projected level of future operations without triggering PSD review. However, WEPCO did not want to be constrained by new source requirements, and so sought review in the Seventh Circuit Court of Appeals.

B. The Court's Decision.

1. Physical Change.

The court unequivocally agreed with EPA that the replacement of steam drums, air heaters, and other major components was a nonroutine "physical change," and thus met the first of two tests for a modification under NSPS and PSD. The Agency found that the renovations proposed by WEPCO were exactly the type of industrial changes that were meant to be addressed by the NSPS and PSD programs. In upholding EPA's finding that a physical change would occur, the court strongly endorsed EPA's reading of the basic congressional intent in adopting the modification provisions of the NSPS and PSD programs, because to rule otherwise "would open vistas of indefinite immunity from the provisions of NSPS and PSD" (slip op. at 11). The court also relied on the reasonableness of EPA's consideration of the magnitude, purpose, frequency, and cost of the work in upholding EPA's finding that the renovations are not "routine" (slip op. at 14-18). In addition, the court rejected WEPCO's argument that the renovations could not be deemed a modification for NSPS purposes because they did not constitute a "reconstruction" under 40 CFR 60.15 (slip op. at 18-20).

2. NSPS Emissions Increase.

The court upheld EPA's decision that there would be an increase in hourly emissions at three of the units, and thus for those three units, WEPCO met the second test for NSPS applicability. The Agency had argued that the regulations require NSPS emissions increases to be determined by comparing the current (pre-change) hourly emissions capacity of each affected facility with the post-renovation hourly emissions capacity of each unit. The Seventh Circuit agreed, and rejected WEPCO's argument that original design capacity or past "representative" capacity no longer achievable at the plant should be used for the baseline emissions rate (slip op. at 20-25).

3. PSD Emissions Increase.

The regulatory preamble to the PSD regulations provides that the set of emissions units that have "not begun normal operations" includes both "new or modified" units (45 FR 52676, 52677, 52718) (1980). Consequently, EPA used the "actual-to-potential" calculus in evaluating WEPCO's life extension project. The court rejected this methodology in the case of WEPCO's "like- kind replacement," asserting that EPA's reasoning was circular (slip op. at 28). [In addition, the court held (slip op. at 27 n. 11) that the exemption in 40 CFR 52.21(b)(2)(iii)(f) for emissions increases due to expanded operations did not apply, because WEPCO's increased operations were directly tied to the life extension project.] Instead, the court ruled that EPA should recalculate post-change emissions considering past operating conditions where it is possible to make a more realistic assessment of future emissions (slip op. at 29-31). Alternatively, the court stated that EPA could conduct new rulemaking to explicitly apply the "actual-to-potential" calculus to "like-kind replacements" (slip op. at 30).

II. THE WEPCO DECISION IN THE CONTEXT OF THE PSD PROVISIONS

The Seventh Circuit held that EPA could not wholly disregard past operating history and automatically apply the actual-to-potential methodology for determining PSD applicability to WEPCO's "like-kind replacements." In describing the WEPCO changes as "like-kind replacements" and limiting its decision to such changes, the court did not dispute the correctness of EPA's application of the actual-to-potential test to the full spectrum of new and modified sources not covered by this subcategory of change. The recent decision in Puerto Rican Cement Co. v. EPA, 889 F.2d 292 (1st Cir. 1989), explicitly upheld EPA's position that the actual-to-potential concept should be applied to "modified" emissions units. The First Circuit case involved the modernization and reconfiguration of existing emissions units [see 889 F.2d at 293 (company planned to "convert kiln No. 6 from a 'wet' to a 'dry' cement- making process, and to combine that with Kiln No. 3")]. A key issue was whether EPA properly held that the "modified" units had "not begun normal operation" and therefore the actual-to-potential concept applied in calculating emissions increases. The First Circuit affirmed EPA's position that the actual-to-potential concept should be applied to the company's "modified" units. Puerto Rican Cement, 889 F.2d at 297. Consequently, the court found that both the language and expressed purpose of the regulations indicate that EPA applied the regulations properly in using the actual-to- potential test for a proposed modification. The Seventh Circuit in WEPCO did not dispute the correctness of EPA's application of the actual-to-potential test to the full spectrum of changes not covered by the subcategory of changes (like-kind replacements) created by the court. {Footenote 1.} Therefore, in the case of nonroutine physical or operational changes at an existing major source which are not specifically "like-kind replacements" in nature, EPA will continue to apply the actual-to-potential test for PSD applicability purposes.

1/. EPA will leave to future case by case applicability determinations what is a "like-kind replacement." But for guidance of the parties, EPA presently considers that only for projects that are genuine "like-kind replacements" can future emissions projections be calculated using "estimated future actual emissions" in lieu of potential to emit. EPA does not consider "like-kind replacements" to mean the entire replacement (or reconstruction) of an existing emissions unit with an identical new one or one similar in design or function. Rather, EPA considers "like-kind replacements" to encompass the replacement of components at an emissions unit with the same (or functionally similar) components. Under this interpretation of the term, new components that perform essentially the same function as old ones will be viewed as "like-kind replacements." In addition, even if the design or purpose of a new component is identical to that of an old one, if the new component is part of a project that will fundamentally change the production process at an existing stationary source, this would be beyond the scope of a "like-kind replacement." Under either of those circumstances, it would be unreasonable to rely on pre-modification usage patterns to estimate future levels of capacity utilization. Instead, in such cases, EPA believes that it is reasonable to assume that in the absence of federally-enforceable limits on hours of operation or production rates, the new components may result in a substantial increase over historical levels of utilization of the emissions unit following modification [see Puerto Rican Cement, supra, 889 F.2d at 297 ("a firm's decision to introduce new, more efficient machinery may lead the firm to decide to increase the level of production")] and will compare pre-modification actual emissions to post-modification potential emissions. In addition to this circumstance, there are cases in which sources that undergo changes that qualify as add-on control systems would, under certain circumstances, be exempt from new source review. See Letter to Timothy J. Method, Assistant Commissioner, Indiana Department of Environmental Management, from David Kee, EPA Region V, January 30, 1990.

III. THE AGENCY'S RESPONSE TO THE COURT'S REMAND ORDER

A. The PSD Baseline Emissions.

Determining the "baseline" level of actual emissions before a physical or operational change is a necessary first step to determine if emissions increase as a result of the physical change. The Agency's regulations define the baseline for PSD purposes, as follows:

> In general, actual emissions as of a particular date shall equal the average rate, in tons-per-year (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. 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 [see 40 CFR 52.21(b)(21)(ii)].

The purpose of the definition is to establish a baseline that is "representative" of "normal" source operations prior to the change. The Agency historically has followed a presumption that the most recent 2 years should be used, but has allowed another period where the source demonstrates that recent operations are abnormal [see 40 CFR 52.21(b)(21)(ii); see also 45 FR 52676, 52718 (1980)]. The WEPCO baseline period is an example of this. In this instance, plant utilization was disrupted by physical problems that led to nonroutine physical changes to remedy those problems. Consequently, EPA determined that a period prior to the onset of such problems was representative of normal operations, and as required by its regulations, used this period to establish the baseline. The period used was also within the contemporaneous period specified in 40 CFR 52.21(b)(3)(ii). It should be emphasized that, in the WEPCO case, the parties and the court agreed that 1983-84 (prior to discovery of steam drum cracks) should be the baseline years (slip op. at 26); these years had an average 29 percent utilization rate. We continue to believe this is the appropriate baseline period for the Port Washington renovation.

B. Calculating Post-Change Emissions Under PSD.

The court concluded that "EPA's reliance on an assumed continuous operation as a basis for finding an emissions increase is not properly supported" (slip op. at 30). Although the court held that EPA cannot, in this case, wholly disregard past operating conditions at the plant, it also held that EPA could not reasonably rely on the company's own unenforceable projection of operating conditions (slip op at 29). The court remanded the question of PSD applicability to EPA for further proceedings not inconsistent with its decision.

Before the court remanded EPA's determination, it attempted to ascertain whether, in fact, the proposed project would be a major modification even using the assumptions least likely to result in an emissions increase. The court felt (and we agree) that such a "best" case scenario for

WEPCO would assume that the "present hours and conditions" would not change at all following the renovations (despite, of course, WEPCO's own estimates of at least tripling of utilization over current levels) (slip op. at 31, n. 14). The court, however, lacked the data to make this calculation, so it could not determine whether a major modification would result using a set of assumptions most favorable to WEPCO. Therefore, the court remanded the determination to EPA for further consideration.

A conceivable interpretation of the court's opinion is that EPA must calculate WEPCO's post-modification emissions increases based on "present hours and conditions." However, for the reasons discussed below, EPA believes that this interpretation is incorrect. Under such an interpretation, EPA would determine WEPCO's post-renovation annual emissions in tons per year (tpy) by simply projecting into the future the hours of operation and conditions (i.e., hourly emissions rate) that existed just before the renovations. This is the interpretation urged by WEPCO in a February 9, 1990 letter to EPA. Such a calculus will always result in exactly the same level of emissions before and after the physical change, and thus would always exempt "like-kind replacements" from PSD review. In addition, calculating emissions increases using this assumption would flatly contradict the record in this case. The WEPCO has stated that it will greatly increase capacity utilization over both current levels and the baseline levels used in the previous determinations. Capacity utilization in terms of heat input to the plant (based on nameplate capacity) during 1978-1979 was about 40 percent (Record item 7.4, WEPCO Submission, April 19, 1988 meeting with EPA). During the 1983-1984 baseline period, it was approximately 27 percent. Id. It has since declined to less than 10 percent (1988-1989 data). Id. The WEPCO has advised the State of Wisconin that it intends to return to a forecasted 42 percent utilization level in the years following renovation, with an upper maximum forecast of 50 percent [Letter from Walter Woelfle, WEPCO, to Dale Zeige, Wisconsin Department of Natural Resources, March 29, 1990, Table 7 (enclosed)]. It would be wrong to assume that unit 5 would not be operated at all in the future when an explicit purpose of the renovation is to bring the unit back on line at its original design capacity; moreover, unit 5 is presently inoperative. Most importantly, this methodology is not fairly discernible from any reading of the current regulations. In addition, using "present hours and conditions" would disregard planned changes at WEPCO that will affect the post-renovation hourly emissions rate [e.g., increased capacity, lowering of sulfur content, and enhancement of the electrostatic precipitators (ESP)].

The court upheld EPA's position that increased utilization in the future that is linked to construction or modification activity should not be excluded in determining post-renovation emissions. Nevertheless, the court told EPA not to automatically assume 100 percent utilization in the future when historical data are available. The WEPCO has definite plans to return the plant to historical levels of utilization that are well above baseline levels of utilization, and which could not be physically or economically attained but for the renovation project. Accordingly, EPA believes it is consistent with the court decision for EPA to base its remand decision on these facts and not rely on the present hours and conditions as conclusive of post-renovation emissions. After a thorough review of the possibilities, EPA has concluded that the court intended that estimates of future emissions for WEPCO's "like- kind replacements" should consider historic pre-renovation operating hours and production rates, as well as other relevant factors, in estimating future utilization levels, and should also consider the increased capacity, switching to lower-sulfur fuel, and other changes affecting the hourly emissions rate for PSD purposes. Consequently, for WEPCO's "like-kind replacements," EPA will compare representative actual emissions for the baseline period to estimated future actual emissions based on all the available facts in the record. Specifically, in calculating post-renovation actual emissions, this approach takes into account 1) physical changes and operational restrictions that would affect the hourly emissions rate following the renovation, 2) WEPCO's pre-renovation capacity utilization, and 3) factors affecting WEPCO's likely post-renovation capacity utilization.

To quantify WEPCO's estimated future actual emissions after the proposed changes EPA relied heavily on projected and historical operational data (e.g., fuel consumption, MMBTU consumed) representative of the source. Specifically, the Agency considered available information regarding (1) projected post- change capacity utilization filed with public utility commissions; (2) Federal and State regulatory filings; (3) the source's own representations; and (4) the source's historical operating data. As described below, EPA determined an appropriate utilization factor for future operations and combined this with post-change emissions factors (to the extent they are or will be made federally enforceable) to estimate a future level of annual emissions for the purpose of determining whether the proposed physical and operational changes would be considered a major modification for PSD purposes. Where a significant emissions increase is projected to occur, WEPCO could voluntarily agree to federally-enforceable limits on any aspect of its future operation (including physical capacity and hours of operation) to ensure that no significant emissions increase will occur.

IV. THE AGENCY'S REVISED PSD APPLICABILITY DETERMINATION

A. Estimated Future Actual Emissions.

The Agency has revised its October 14, 1989 PSD applicability determination for WEPCO's proposed Port Washington renovation based on a "representative actual" to "estimated future actual emissions" comparison (as outlined above). As previously discussed, estimated future actual emissions projections take into account the likelihood that the plant will operate in the future as it has in the past.

The stated purpose of WEPCO's renovations is to refurbish the power plant units to an "as-new" condition in terms of their capacity, efficiency, and availability. Consequently, EPA has used actual, historical, operational data representative of the plant's past operations, approximating an "as-new" configuration, to calculate "estimated future actual emissions." The Agency has verified these data by comparison to WEPCO's own projections of post- renovation capacity utilization and industry averages.

As to the emissions factors used to calculate future emissions, EPA has used WEPCO's own emissions factors for future hourly emissions rates. These emissions factors are based on WEPCO's own assumptions regarding future sulfur in fuel and control technology performance levels. However, since these assumptions go beyond current State implementation plan (SIP) requirements, they must be made federally enforceable for EPA to continue to consider them for PSD applicability purposes.

Operational data (i.e., heat input) from the years 1978-1979 show a capacity utilization factor of 42 percent. These data points represent the closest projection of WEPCO's operational characteristics, approximating an "as-new" state, as currently available to EPA. The data currently available to us regarding WEPCO's past operational levels are limited to a 10-year period. The Agency believes that these historical levels of operation are representative of the plant's past operations in an "as-new" condition. In addition, the 1978-79 data points appear consistent with WEPCO's own projection of future operations for the year 2010 (as submitted to the Wisconsin Department of Natural Resources on March 29, 1990) and common capacity levels for the utility industry, in general, for new units. However, by this letter, EPA is requesting that WEPCO submit operational data from previous years (i.e., pre-1978), if such data show heat input levels notably higher than the 1978-1979 levels.

As previously mentioned, to calculate future emissions levels for each pollutant, EPA assumed that the amount of future coal consumed in terms of heat input to the plant would be comparable to WEPCO's annual average 1978- 1979 coal-consumption figure. On March 29, 1990, WEPCO submitted to the Wisconsin Department of Natural Resources information which contained estimates of future emissions for different levels of coal and heat input to the plant. The Agency used these estimates to establish future emissions based on 1978-1979 heat-input values. Again, it is important to note that EPA's calculation of "estimated future actual emissions" is based on WEPCO's projection of control technology performance levels and/or fuel sulfur content for post-renovation operations. Consequently, EPA's PSD applicability determination is valid only to the extent that the emissions factors (based on control technology performance levels and sulfur in fuel) used to calculate future emissions are made federally enforceable. Otherwise, the calculation of estimated future actual emissions for each pollutant will need to be revised by EPA based on existing federally-enforceable limits (i.e., applicable SIP, NSPS). The use of current, federally-enforceable emissions in the current SIP would result in higher projected future emissions than assumed in EPA's calculations and, consequently, could affect the indicated PSD applicability finding.

B. Revised Finding

In sum, EPA has considered past operations at WEPCO's Port Washington plant in estimating future actual emissions. Specifically, EPA has relied on the 42 percent utilization level (in terms of heat input) during 1978-1979. The Agency believes this is a reliable indicator of future utilization because it is consistent both with WEPCO's own projections of post-renovation operations and typical industry usage. The Agency has also considered post- renovation emissions rates on the assumption that they will be made federally enforceable. Compared to the 1983-1984 baseline period, those hourly rates are lower for SO2 and PM, and unchanged for NOx. The 42 percent estimated post-renovation capacity utilization is substantially higher than the 29 percent utilization level during the baseline period. However, in calculating total annual actual emissions, that increased usage is offset for SO2 and PM by the decreased hourly emissions rates resulting from improvements to control systems and the use of low sulfur coal. Consequently, WEPCO is not subject to PSD review for those pollutants.

In the case of NOx, there will be a direct correlation between increased utilization resulting from the renovations and increased actual emissions. Hence, WEPCO is subject to review for that pollutant and must obtain a PSD permit. The company should contact the Wisconsin Department of Natural Resources regarding the processing of a permit application for NOx. Due to insufficient source-specific information regarding emissions factors, PSD applicability for PM-10, lead, and noncriteria pollutants listed at 40 CFR 52.21 (b)(23)(i) and (ii) cannot be determined at this time. The PSD applicability for these pollutants should also be based on the "actual-to- actual" emissions test described herein.

This PSD applicability determination applies to WEPCO's currently planned renovations to units 1-5 (see Enclosure A), or, if WEPCO no longer wishes to proceed with renovating unit 5, only the renovation of units 1-4 (see Enclosure B). However, a decision to cancel the currently planned renovations to unit 5 could result in a PSD review for that unit should WEPCO reconsider renovating it some time in the future.

It is our understanding that WEPCO proposes to avoid triggering NSPS for SO2 and PM at units 1 and 4 by using dry sorbent injection and improving the existing ESP's to offset the potential emissions increases of these pollutants. To the extent that the controls are federally enforceable, and no increase in hourly emissions would occur at maximum capacity, WEPCO can use these options to avoid triggering NSPS for PM and SO2 at units 1 and 4. However, the two units are still subject to the NSPS requirements for NOx. Unit 5 cannot, however, avoid triggering NSPS for any pollutant and, therefore, is subject to the NSPS requirements for NOx, SO2, and PM.

Sincerely,

William G. Rosenberg
Assistant Administrator
for Air and Radiation

3 Enclosures

Table 7

PORT WASHINGTON POWER PLANT
MAY 1989 FORECAST
Units 1 - 5

YEAR	MEGAWATT HOURS GENERATED	FUEL CONSUMPTION CAPACITY FACTOR	COAL (13200 Btu/lb) BURNED TONS
1995	825,288	0.24	365,548
1996	941,779	0.27	415,332
1997	1,081,002	0.31	475,624
1998	1,114,313	0.32	490,868
1999	1,247,296	0.36	546,546
2000	1,349,329	0.38	589,569
2001	1,391,882	0.40	608,621
2002	1,481,464	0.42	646,417
2003	1,420,120	0.41	620,153
2004	1,432,122	0.41	625,174
2005	1,431,412	0.41	624,904
2006	1,460,471	0.42	637,519
2007	1,488,124	0.42	649,133
2008	1,481,423	0.42	646,909
2009	1,463,981	0.42	638,750

PORT WASHINGTON POWER PLANT
UPPER MAXIMUM FORECAST
Units 1 - 5

YEAR	MEGAWATT HOURS GENERATED	FUEL CAPACITY FACTOR	CONSUMPTION COAL (13200 Btu/lb) BURNED TONS
1995	1,074,957	0.24	473,981
1996	1,202,460	0.27	528,838
1997	1,341,074	0.38	587,412
1998	1,390,470	0.40	609,237
1999	1,501,584	0.43	654,718
2000	1,600,500	0.46	696,483
2001	1,651,930	0.47	718,252
2002	1,748,046	0.50	760,000
2003	1,690,000	0.48	735,000
2004	1,690,000	0.48	734,000
2005	1,690,000	0.48	734,000
2006	1,710,000	0.49	741,000
2007	1,720,000	0.49	748,000
2008	1,720,000	0.49	747,000
2009	1,695,000	0.48	737,000

Enclosure A

Revised PSD Applicability Determination
Port Washington Power Plant Renovation of Units 1-5

(all emissions calculations are in tons per year)

Pollutant	Actual Emissions Baseline (1)	Estimated Future Actual Emissions(2)	Net Emissions Change	PSD Significance Level	Subject to PSD Review
Particulate matter (4) (5)	328	323	-5	25	no
Sulfur dioxide (4)	24,236	15,919	-8,317	40	no
Nitrogen oxides (5)	2,592	3,405	813	40	yes
Carbon monoxide	144	217	73	100	no
Hydrocarbon	17	25	9	40	no

Other Regulated Pollutants: Due to insufficient source-specific information regarding emission factors, PSD applicability for PM-10, lead and noncriteria pollutants listed at 40 CFR Section 52.21 (b)(23)(i) and (ii) cannot be determined at this time.

1) Average actual emissions for 2-year period defined by calendar years 1983 and 1984.

2) Calculated by EPA based on the following information submitted by WEPCO:

a. The average historic firing rate (approximately 17x106 Mbtu per year) for the 2-year period defined by calendar years 1978 and 1979.

b. The emissions estimates for the renovated units based on future coal characteristics (e.g., sulfur and heat content) and actual emissions after pollution controls for particulate.

c. Sulfur dioxide controls applied to unit 5 at 75 percent sulfur dioxide removal to comply with NSPS Subpart Da. Sulfur dioxide removal of 22 and 13 percent at units 1 and 4, respectively, to exclude these units from NSPS requirements for greater control of sulfur dioxide.

3) If new data indicate that annual, historic-firing rates at the Port Washington facility exceeded historic 1978 and 1979 levels, the indicated applicability determination could change.

4) The calculation of estimated, future, actual emissions for this pollutant is based on WEPCO's projection of control technology performance levels and/or fuel sulfur content for post-renovation operations. Consequently, EPA's PSD applicability determination is valid only to the extent that the specific particulate and sulfur dioxide emissions factors used for units 1-5 to calculate future emissions (based on particulate and S02 control technology performance levels and fuel sulfur and heat content) are made federally enforceable. Otherwise, the calculation of estimated, future, actual emissions for this pollutant will be revised by EPA, based on existing federally-enforceable limits (i.e., applicable SIP, NSPS). The use of current, federally-enforceable emissions factors would result in higher, projected, future emissions and, consequently, could affect the indicated PSD applicability finding.

5) Baseline emissions (actual emissions for 2-year period defined by calendar years 1983 and 1984) have been revised based on additional information submitted by WEPCO.

Enclosure B

Revised PSD Applicability Determination
Port Washington Power Plant Renovation of Units 1-4
(all emissions calculations are in tons per year)

Pollutant	Actual Emissions Baseline (1)	Estimated Future Actual Emissions(2)	Net Emissions Change	PSD Significance Level	Subject to PSD Review
Particulate matter (4) (5)	328	339	11	25	no
Sulfur dioxide (4)	24,236	18,505	-5,731	40	no
Nitrogen oxides (5)	2,592	3,396	804	40	yes
Carbon monoxide	144	217	73	100	no
Hydrocarbon	17	25	9	40	no

Other Regulated Pollutants: Due to insufficient source specific information regarding emission factors, PSD applicability for PM-10, lead and noncriteria pollutants listed at 40 CFR Section 52.21 (b)(23)(i) and (ii) cannot be determined at this time.

1) Average actual emissions for 2-year period defined by calendar years 1983 and 1984.

2) Calculated by EPA based on the following information submitted by WEPCO:

a. The average, historic-firing rate (approximately 17x106 Mbtu per year) for the 2-year period defined by calendar years 1978 and 1979.

b. The emissions estimates for the renovated units based on future coal characteristics (e.g., sulfur and heat content) and actual emissions after pollution controls for particulate.

c. Unit 5 inoperative. Sulfur dioxide removal of 22 and 13 percent at units 1 and 4, respectively, to exclude these units from NSPS requirements for greater control of sulfur dioxide.

3) If new data indicate that annual, historic-firing rates at the Port Washington facility exceeded historic 1978 and 1979 levels, the indicated applicability determination could change.

4) The calculation of estimated, future, actual emissions for this pollutant is based on WEPCO's projection of control technology performance levels and/or fuel sulfur content for post renovation operations. Consequently, EPA's PSD applicability determination is valid only to the extent that the specific particulate and sulfur dioxide emissions factors used for units 1-4 to calculate future emissions (based on particulate and S02 control technology performance levels and fuel sulfur and heat content) are made federally enforceable. Otherwise, the calculation of estimated, future, actual emissions for this pollutant will be revised by EPA, based on existing federally - enforceable limits (i.e., applicable SIP, NSPS). The use of current, federally-enforceable emissions factors would result in higher, projected, future emissions and, consequently, could affect the indicated PSD applicability finding.

5) Baseline emissions (actual emissions for 2-year period defined by calendar years 1983 and 1984) have been revised based on additional information submitted by WEPCO.