INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT

We Protect Hoosiers and Our Environment.

Mitchell E. Daniels Jr.
Governor

Thomas W. Easterly
Commissioner

100 North Senate Avenue
Indianapolis, Indiana 46204
(317) 232-8603
Toll Free (800) 451-6027
www.idem.IN.gov

TO: Interested Parties / Applicant

DATE: September 10, 2009

RE: Electric Coating Technologies, LLC / 089-28195-00373

FROM: Matthew Stuckey, Branch Chief
Permits Branch
Office of Air Quality

Notice of Decision: Approval - Registration

Please be advised that on behalf of the Commissioner of the Department of Environmental Management, I have issued a decision regarding the enclosed matter. Pursuant to IC 4-21.5-3-4(d) this order is effective when it is served. When served by U.S. mail, the order is effective three (3) calendar days from the mailing of this notice pursuant to IC 4-21.5-3-2(e).

If you wish to challenge this decision, IC 4-21.5-3-7 requires that you file a petition for administrative review. This petition may include a request for stay of effectiveness and must be submitted to the Office of Environmental Adjudication, 100 North Senate Avenue, Government Center North, Suite N 501E, Indianapolis, IN 46204, **within eighteen (18) calendar days of the mailing of this notice**. The filing of a petition for administrative review is complete on the earliest of the following dates that apply to the filing:

(1) the date the document is delivered to the Office of Environmental Adjudication (OEA);
(2) the date of the postmark on the envelope containing the document, if the document is mailed to OEA by U.S. mail; or
(3) The date on which the document is deposited with a private carrier, as shown by receipt issued by the carrier, if the document is sent to the OEA by private carrier.

The petition must include facts demonstrating that you are either the applicant, a person aggrieved or adversely affected by the decision or otherwise entitled to review by law. Please identify the permit, decision, or other order for which you seek review by permit number, name of the applicant, location, date of this notice and all of the following:

(1) the name and address of the person making the request;
(2) the interest of the person making the request;
(3) identification of any persons represented by the person making the request;
(4) the reasons, with particularity, for the request;
(5) the issues, with particularity, proposed for considerations at any hearing; and
(6) identification of the terms and conditions which, in the judgment of the person making the request, would be appropriate in the case in question to satisfy the requirements of the law governing documents of the type issued by the Commissioner.

If you have technical questions regarding the enclosed documents, please contact the Office of Air Quality, Permits Branch at (317) 233-0178. Callers from within Indiana may call toll-free at 1-800-451-6027, ext. 3-0178.

Enclosures
FN-REGIS.dot 1/2/08

IDEM

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Kenneth Paxson
Electric Coating Technologies, LLC
4407 Railroad Avenue
East Chicago, Indiana 46312

September 10,2009

Re: 089-28195-00373
Re- Registration of R089-13740-00373

Dear Mr. Paxson:

Great Lake Metals, LLC (previous owner) was issued a Registration No. 089-13740-00373 on October 12, 2001 for a stationary continuous coil electrogalvanizing plant located at 4407 Railroad Avenue, East Chicago, Indiana. On July 2, 2009, the Office of Air Quality (OAQ) received a letter from Electric Coating Technologies, LLC (current owner) requesting that the registration be reviewed to determine whether their existing permit remained applicable.

After verifying the information and calculations submitted by Electric Coating Technologies, LLC, IDEM has re-issued this registration to indicate an updated review of applicable requirements. The changes to the registration are considered a re-Registration pursuant to 326 IAC 2-5.5-6(d)(2).

IDEM, OAQ has decided to make additional revisions to the registration as described below. The registration has been revised as follows with deleted language as ~~strikeouts~~ and new language **bolded**:

1. Several of IDEM's branches and sections have been renamed. Therefore, IDEM has updated the addresses listed in the registration. References to "Compliance Data Section" and "Compliance Branch" have been changed to "Compliance and Enforcement Branch". The registration has been revised as follows:

   ~~Compliance Data Section~~ **Compliance and Enforcement Branch**
   ~~Compliance Branch~~ **Compliance and Enforcement Branch**

The following conditions have been added to clarify the requirements of the registration:

(1) Examination of the MSDS of the substance used in the electrostatic oiler revealed a VOC content of 6.1%. Therefore, the requirements under Article 8 were evaluated and IDEM determined that 326 IAC 8-2-4 (Coil Coating Operations) is applicable. The requirements for this rule have been added as Conditions D.2.2, D.2.3 & D.2.4.

Emission Limitations and Standards [326 IAC 2-5.1-2(f)(1)] [326 IAC 2-5.5-4(a)(1)]

D.2.2 Volatile Organic Compound (VOC) [326 IAC 8-2]

Pursuant to 326 IAC 8-2-4 (Coil Coating Operations), the daily volume weighted average volatile organic compound (VOC) content of coating delivered to the applicators at the electrostatic oiler shall be limited to 2.6 pounds of VOC per gallon of coating less water.

Compliance Determination Requirements [326 IAC 2-5.1-2(g)] [326 IAC 2-5.5-4(b)]

D.2.3 Volatile Organic Compounds

Compliance with the VOC content and usage limitations contained in Condition D.2.2 shall be determined pursuant to 326 IAC 8-1-4(a)(3)(A) using formulation data supplied by the coating manufacturer. However, IDEM, OAQ reserves the authority to determine compliance using Method 24 in conjunction with the analytical procedures specified in 326 IAC 8-1-4.

Record Keeping and Reporting Requirements [326 IAC 2-5.1-2(g)] [326 IAC 2-5.5-4(b)]

D.2.4 Record Keeping Requirements

(a) To document compliance with Condition D.2.2, the Permittee shall maintain records in accordance with (1) through (2) below. Records maintained for (1) through (2) shall be taken monthly and shall be complete and sufficient to establish compliance with the VOC usage limits and/or the VOC emission limits established in Condition D.2.2. Records necessary to demonstrate compliance shall be available within 30 days of the end of each compliance period.

(1) The VOC content of each coating material and solvent used.

(2) The amount of coating material and solvent less water used on a monthly basis.

(A) Records shall include purchase orders, invoices, and material safety data sheets (MSDS) necessary to verify the type and amount used.

(B) Solvent usage records shall differentiate between those added to coatings and those used as cleanup solvents.

(b) All records shall be maintained in accordance with Section C - General Record Keeping Requirements, of this permit.

The source shall continue to operate according to 326 IAC 2-5.5. Please find enclosed the revised registration. A copy of the registration is available on the Internet at: http://www.in.gov/ai/appfiles/idem-caats/. For additional information about air permits and how the public and interested parties can participate, refer to the IDEM's Guide for Citizen Participation and Permit Guide on the Internet at: www.idem.in.gov

This decision is subject to the Indiana Administrative Orders and Procedures Act - IC 4-21.5-3-5. If you have any questions on this matter, please contact Sandra Carr, at (800) 451-6027, press 0 and ask for Sandra Carr or extension 45372, or dial (317) 234-5372.

Sincerely,

Iryn Calilung

Iryn Calilung, Section Chief
Permits Branch
Office of Air Quality

IC/sec

Attachment: Revised Registration
cc: File - Lake County
Lake County Health Department
Compliance and Enforcement Branch
Billing, Licensing and Training Section

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Re-REGISTRATION

OFFICE OF AIR QUALITY

Electric Coating Technologies, LLC
4407 Railroad Avenue
East Chicago, Indiana 46312

Pursuant to 326 IAC 2-5.1 (Construction of New Sources: Registrations) and 326 IAC 2-5.5 (Registrations), (herein known as the Registrant) is hereby authorized to construct and operate subject to the conditions contained herein, the source described in Section A (Source Summary) of this registration.

Registration No. 089-28195-00373	
Issued by: Iryn Calilung, Section Chief Permits Branch Office of Air Quality	Issuance Date: September 10, 2009

SECTION A SOURCE SUMMARY

This registration is based on information requested by the Indiana Department of Environmental Management (IDEM), Office of Air Quality (OAQ). The information describing the source contained in conditions A.1 and A.2 is descriptive information and does not constitute enforceable conditions. However, the Registrant should be aware that a physical change or a change in the method of operation that may render this descriptive information obsolete or inaccurate may trigger requirements for the Registrant to obtain additional permits pursuant to 326 IAC 2.

A.1 General Information

The Registrant owns and operates a stationary continuous coil electrogalvanizing source.

Source Address:	4407 Railroad Avenue, East Chicago, Indiana 46312
Mailing Address:	4407 Railroad Avenue, East Chicago, Indiana 46312
General Source Phone Number:	(219) 378-1930
SIC Code:	3313
County Location:	Lake County
Source Location Status:	Nonattainment for 8-hour ozone standard Nonattainment for $PM_{2.5}$ standard Attainment for all other criteria pollutants
Source Status:	Registration

A.2 Emission Units and Pollution Control Equipment Summary

This stationary source consists of the following emission units and pollution control devices:

(a) Two (2) natural gas-fired boilers, identified as Boiler #2 and Boiler #3, constructed after June 9, 1989, each equipped with low NO_X burners, each with a capacity of 21.0 million British thermal units per hour, with no control, exhausting to stacks SS-2 & SS-3, respectively.

Under New Source Performance Standards for Small Industrial-Commercial-Institutional Steam Generating Units, 60.40c, Subpart Dc, the boilers, identified as Boiler #2 and Boiler #3, are considered affected sources.

(b) One (1) electrogalvanizing line, coating coiled metal strips, consisting of multiple stations including: pre-cleaning, degreasing, zinc galvanizing, phosphate & chromium baths, and electrostatic oiling. This line has a maximum operating capacity of 350 feet of metal coil per minute, with a wet scrubber, identified as the plating fume scrubber, for particulate control, exhausting to stacks SS-1, SS-4, SS-5, and SS-6.

(c) Two (2) natural gas fired space heaters, identified as #1 West and #2 East, each with a capacity of 8.80 million British thermal units per hour, with no control, exhausting inside the building.

SECTION B GENERAL CONDITIONS

B.1 Definitions [326 IAC 2-1.1-1]

Terms in this registration shall have the definition assigned to such terms in the referenced regulation. In the absence of definitions in the referenced regulation, the applicable definitions found in the statutes or regulations (IC 13-11, 326 IAC 1-2 and 326 IAC 2-1.1-1) shall prevail.

B.2 Effective Date of Registration [IC 13-15-5-3]

Pursuant to IC 13-15-5-3, this registration is effective immediately, unless a petition for stay of effectiveness is filed and granted according to IC 13-15-6-3, and may be revoked or modified in accordance with the provisions of IC 13-15-7-1.

B.3 Registration Revocation [326 IAC 2-1.1-9]

Pursuant to 326 IAC 2-1.1-9 (Revocation), this registration to operate may be revoked for any of the following causes:

(a) Violation of any conditions of this registration.

(b) Failure to disclose all the relevant facts, or misrepresentation in obtaining this registration.

(c) Changes in regulatory requirements that mandate either a temporary or permanent reduction of discharge of contaminants. However, the amendment of appropriate sections of this registration shall not require revocation of this registration.

(d) For any cause which establishes in the judgment of IDEM the fact that continuance of this registration is not consistent with purposes of this article.

B.4 Prior Permits Superseded [326 IAC 2-1.1-9.5]

(a) All terms and conditions of permits established prior to Registration No. 089-28195-00373 and issued pursuant to permitting programs approved into the state implementation plan have been either:

(1) incorporated as originally stated,

(2) revised, or

(3) deleted.

(b) All previous registrations and permits are superseded by this registration.

B.5 Annual Notification [326 IAC 2-5.1-2(f)(3)] [326 IAC 2-5.5-4(a)(3)]

Pursuant to 326 IAC 2-5.1-2(f)(3) and 326 IAC 2-5.5-4(a)(3):

(a) An annual notification shall be submitted by an authorized individual to the Office of Air Quality stating whether or not the source is in operation and in compliance with the terms and conditions contained in this registration.

(b) The annual notice shall be submitted in the format attached no later than March 1 of each year to:

Indiana Department of Environmental Management
Compliance and Enforcement Branch, Office of Air Quality
100 North Senate Avenue
MC 61-53 IGCN 1003
Indianapolis, IN 46204-2251

(c) The notification shall be considered timely if the date postmarked on the envelope or certified mail receipt, or affixed by the shipper on the private shipping receipt, is on or before the date it is due. If the document is submitted by any other means, it shall be considered timely if received by IDEM, OAQ on or before the date it is due.

B.6 Source Modification Requirement [326 IAC 2-5.5-6(a)]

Pursuant to 326 IAC 2-5.5-6(a), an application or notification shall be submitted in accordance with 326 IAC 2 to the Office of Air Quality (OAQ) if the source proposes to construct new emission units, modify existing emission units, or otherwise modify the source.

B.7 Registrations [326 IAC 2-5.1-2(i)]

Pursuant to 326 IAC 2-5.1-2(i), this registration does not limit the source's potential to emit.

SECTION C SOURCE OPERATION CONDITIONS

Entire Source

Emission Limitations and Standards [326 IAC 2-5.1-2(g)] [326 IAC 2-5.5-4(b)]

C.1 Opacity [326 IAC 5-1]

Pursuant to 326 IAC 5-1-2 (Opacity Limitations), except as provided in 326 IAC 5-1-3 (Temporary Alternative Opacity Limitations), opacity shall meet the following, unless otherwise stated in this registration:

(a) Opacity shall not exceed an average of twenty percent (20%) in any one (1) six (6) minute averaging period as determined in 326 IAC 5-1-4.

(b) Opacity shall not exceed sixty percent (60%) for more than a cumulative total of fifteen (15) minutes (sixty (60) readings as measured according to 40 CFR 60, Appendix A, Method 9 or fifteen (15) one (1) minute nonoverlapping integrated averages for a continuous opacity monitor) in a six (6) hour period.

C.2 Fugitive Dust Emissions [326 IAC 6-4]

The Registrant shall not allow fugitive dust to escape beyond the property line or boundaries of the property, right-of-way, or easement on which the source is located, in a manner that would violate 326 IAC 6-4 (Fugitive Dust Emissions).

SECTION D.1 OPERATION CONDITIONS

Facility Description [326 IAC 2-5.1-2(f)(2)] [326 IAC 2-5.5-4(a)(2)]:

(a) Two (2) natural gas-fired boilers, identified as Boiler #2 and Boiler #3, constructed after June 9, 1989, each equipped with low NO_X burners, each with a capacity of 21.0 million British thermal units per hour, with no control, exhausting to stacks SS-2 & SS-3, respectively.

Under New Source Performance Standards for Small Industrial-Commercial-Institutional Steam Generating Units, 60.40c, Subpart Dc, the boilers, identified as Boiler #2 and Boiler #3, are considered affected sources.

(The information describing the process contained in this emissions unit description box is descriptive information and does not constitute enforceable conditions.)

Emission Limitations and Standards [326 IAC 2-5.1-2(f)(1)] [326 IAC 2-5.5-4(a)(1)]

D.1.1 Particulate [326 IAC 6-2-4]

Pursuant to 326 IAC 6-2-4 (Particulate Emission Limitations for Sources of Indirect Heating), the PM from each of the two (2) natural gas-fired boilers, identified as Boiler #2 & Boiler #3, shall be limited to 0.41 pounds per million British thermal unit of heat input. The emission limitations are based on the following equation is given in 326 IAC 6-2-4:

$$Pt = 1.09/Q^{0.26}$$

where:

Pt = Pounds of particulate matter emitted per million British thermal units (lb/MMBtu) heat input

Q = Total source maximum operating capacity rating in million British thermal units per hour (MMBtu/hr) heat input. The maximum operating capacity rating is defined as the maximum capacity at which the facility is operated or the nameplate capacity, whichever is specified in the facility's permit application, except when some lower capacity is contained in the facility's operation permit; in which case, the capacity specified in the operation permit shall be used.

Operating these boilers, Boiler #2 & Boiler #3, using fuels other than natural gas shall require prior IDEM, OAQ, approval.

SECTION D.2 OPERATION CONDITIONS

Facility Description [326 IAC 2-5.1-2(f)(2)] [326 IAC 2-5.5-4(a)(2)]:

(b) One (1) electrogalvanizing line, coating coiled metal strips, consisting of multiple stations including: pre-cleaning, degreasing, zinc galvanizing, phosphate & chromium baths, and electrostatic oiling. This line has a maximum operating capacity of 350 feet of metal coil per minute, with a wet scrubber, identified as the plating fume scrubber, for particulate control, exhausting to stacks SS-1, SS-4, SS-5, and SS-6.

(The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

Emission Limitations and Standards [326 IAC 2-5.1-2(f)(1)] [326 IAC 2-5.5-4(a)(1)]

D.2.1 Particulate [326 IAC 6-3-2]

Pursuant to 326 IAC 6-3-2 (Process Operations), the particulate matter (PM) from the electrogalvanizing line shall not exceed 55.2 pounds per hour, when operating at a process weight rate of 292,000 pounds (146 tons) per hour.

Interpolation of the data for the process weight rate up to sixty thousand (60,000) pounds per hour shall be accomplished by use of the equation:

$$E = 4.10 P^{0.67}$$

where
E = rate of emission in pounds per hour and
P = process weight rate in tons per hour

D.2.2 Volatile Organic Compound (VOC) [326 IAC 8-2]

Pursuant to 326 IAC 8-2-4 (Coil Coating Operations), the daily volume weighted average volatile organic compound (VOC) content of coating delivered to the applicators at the electrostatic oiler shall be limited to 2.6 pounds of VOC per gallon of coating less water.

Compliance Determination Requirements [326 IAC 2-5.1-2(g)] [326 IAC 2-5.5-4(b)]

D.2.3 Volatile Organic Compounds

Compliance with the VOC content and usage limitations contained in Condition D.2.2 shall be determined pursuant to 326 IAC 8-1-4(a)(3)(A) using formulation data supplied by the coating manufacturer. However, IDEM, OAQ reserves the authority to determine compliance using Method 24 in conjunction with the analytical procedures specified in 326 IAC 8-1-4.

Record Keeping and Reporting Requirements [326 IAC 2-5.1-2(g)] [326 IAC 2-5.5-4(b)]

D.2.4 Record Keeping Requirements

(a) To document compliance with Condition D.2.2, the Permittee shall maintain records in accordance with (1) through (2) below. Records maintained for (1) through (2) shall be taken monthly and shall be complete and sufficient to establish compliance with the VOC usage limits and/or the VOC emission limits established in Condition D.2.2. Records necessary to demonstrate compliance shall be available within 30 days of the end of each compliance period.

(1) The VOC content of each coating material and solvent used.

(2) The amount of coating material and solvent less water used on a monthly basis.

(A) Records shall include purchase orders, invoices, and material safety data sheets (MSDS) necessary to verify the type and amount used.

(B) Solvent usage records shall differentiate between those added to coatings and those used as cleanup solvents.

(b) All records shall be maintained in accordance with Section C - General Record Keeping Requirements, of this permit.

SECTION E.1 OPERATION CONDITIONS

Facility Description [326 IAC 2-5.1-2(f)(2)] [326 IAC 2-5.5-4(a)(2)]:

(a) Two (2) natural gas fired boilers, identified as Boiler #2 and Boiler #3, constructed after June 9, 1989, each equipped with low NO_X burners, each with a capacity of 21.0 million British thermal units per hour, with no control, exhausting to stacks SS-2 & SS-3, respectively.

Under New Source Performance Standards for Small Industrial-Commercial-Institutional Steam Generating Units, 60.40c, Subpart Dc, the boilers, identified as Boiler #2 and Boiler #3, are considered affected sources.

(The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

E.1.1 General Provisions Relating to New Source Performance Standards (NSPS) for Small Industrial-Commercial-Institutional Steam Generating Units [40 CFR Part 60, Subpart A] [326 IAC 12-1]

(a) Pursuant to 40 CFR 60.1, the Permittee shall comply with the provisions of 40 CFR Part 60, Subpart A - General Provisions, which are incorporated by reference as 326 IAC 12-1, except as otherwise specified in 40 CFR 60, Subpart Dc.

(b) Pursuant to 40 CFR 60.10, the Permittee shall submit all required notifications and reports to:

Indiana Department of Environmental Management
Compliance and Enforcement Branch, Office of Air Quality
100 North Senate Avenue
MC 61-53 IGCN 1003
Indianapolis, Indiana 46204-2251

E.1.2 NSPS Subpart Dc: Affected Facilities [40 CFR Part 60, Subpart Dc] [326 IAC 12-1]

Pursuant to 40 CFR 60.40c(a), for the purposes of this subpart, an affected facility is each steam generating unit constructed after June 9, 1989, having a maximum heat input capacity which is greater than 10 million British thermal units per hour and less than 100 million British thermal units per hour (MMBtu/hr).

At this source, the affected facilities associated to which the provisions of this subpart apply are:

Two (2) natural gas-fired boilers, identified as Boiler-2 and Boiler-3.

E.1.3 NSPS Subpart Dc: Applicable Requirements [40 CFR Part 60, Subpart Dc] [326 IAC 12-1]

The Registrant, which engages in the operation of two small natural gas fired steam generating units, shall comply with the following provisions of 40 CFR Part 60, Subpart Dc (included as Attachment A of this permit):

(1) 40 CFR 60.40c(a)
(2) 40 CFR 60.40c(b)
(3) 40 CFR 60.40c(c)
(4) 40 CFR 60.40c(d)
(5) 40 CFR 60.41c
(6) 40 CFR 60.48c(a)(1)
(7) 40 CFR 60.48c(a)(3)
(8) 40 CFR 60.48c(g)(2)
(9) 40 CFR 60.48c(g)(3)

(10) 40 CFR 60.48c(i)
(11) 40 CFR 60.48c(j)

Operating on fuels other than natural gas may cause the requirements of 40 CFR 60.42c, 40 CFR 60.43c, 40 CFR 60.44c, 40 CFR 60.45c, 40 CFR 60.46c and 40 CFR 60.47c to be applicable to the two (2) boilers, identified as Boiler-2 and Boiler-3, and shall require prior IDEM, OAQ, approval.

The provisions of 40 CFR 60 Subpart A – General Provisions, which are incorporated as 326 IAC 12-1, apply to the affected facilities described in this section, except when otherwise specified in 40 CFR 60, Subpart Dc.

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
OFFICE OF AIR QUALITY
COMPLIANCE AND ENFORCEMENT BRANCH

REGISTRATION
ANNUAL NOTIFICATION

This form should be used to comply with the notification requirements under 326 IAC 2-5.1-2(f)(3) and 326 IAC 2-5.5-4(a)(3).

Company Name:	Electric Coating Technologies, LLC
Address:	4407 Railroad Avenue
City:	East Chicago, Indiana 46312
Phone Number:	(219) 378-1930
Registration No.:	089-28195-00373

I hereby certify that Electric Coating Technologies, LLC is :
- ☐ still in operation.
- ☐ no longer in operation.

I hereby certify that Electric Coating Technologies, LLC is :
- ☐ in compliance with the requirements of Registration No. 089-28195-00373.
- ☐ not in compliance with the requirements of Registration No. 089-28195-00373.

Authorized Individual (typed):
Title:
Signature:
Phone Number:
Date:

If there are any conditions or requirements for which the source is not in compliance, provide a narrative description of how the source did or will achieve compliance and the date compliance was, or will be achieved.

Noncompliance:

Attachment A

New Source Performance Standards (NSPS) for

Small Industrial-Commercial-Institutional Steam Generating Units

40 CFR 60.40c, Subpart Dc

In support of a Registration

Source Name:	Electric Coatings Technologies, LLC
Source Location:	4407 Railroad Avenue, East Chicago, Indiana 46312
County:	Lake
SIC Code:	3714
Operation Permit No.:	089-28195-00373
Permit Reviewer:	Sandra Carr

Subpart Dc—
Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units

Title 40: Protection of Environment
Part 60—Standards of Performance for New Stationary Sources
e-CFR Data is current as of June 12, 2009
Source: 72 FR 32759, June 13, 2007, unless otherwise noted.

§ 60.40c Applicability and delegation of authority.

(a) Except as provided in paragraphs (d), (e), (f), and (g) of this section, the affected facility to which this subpart applies is each steam generating unit for which construction, modification, or reconstruction is commenced after June 9, 1989 and that has a maximum design heat input capacity of 29 megawatts (MW) (100 million British thermal units per hour (MMBtu/hr)) or less, but greater than or equal to 2.9 MW (10 MMBtu/hr).

(b) In delegating implementation and enforcement authority to a State under section 111(c) of the Clean Air Act, §60.48c(a)(4) shall be retained by the Administrator and not transferred to a State.

(c) Steam generating units that meet the applicability requirements in paragraph (a) of this section are not subject to the sulfur dioxide (SO_2) or particulate matter (PM) emission limits, performance testing requirements, or monitoring requirements under this subpart (§§60.42c, 60.43c, 60.44c, 60.45c, 60.46c, or 60.47c) during periods of combustion research, as defined in §60.41c.

(d) Any temporary change to an existing steam generating unit for the purpose of conducting combustion research is not considered a modification under §60.14.

(e) Heat recovery steam generators that are associated with combined cycle gas turbines and meet the applicability requirements of subpart KKKK of this part are not subject to this subpart. This subpart will continue to apply to all other heat recovery steam generators that are capable of combusting more than or equal to 2.9 MW (10 MMBtu/hr) heat input of fossil fuel but less than or equal to 29 MW (100 MMBtu/hr) heat input of fossil fuel. If the heat recovery steam generator is subject to this subpart, only emissions resulting from combustion of fuels in the steam generating unit are subject to this subpart. (The gas turbine emissions are subject to subpart GG or KKKK, as applicable, of this part).

(f) Any facility covered by subpart AAAA of this part is not subject by this subpart.

(g) Any facility covered by an EPA approved State or Federal section 111(d)/129 plan implementing subpart BBBB of this part is not subject by this subpart.

[72 FR 32759, June 13, 2007, as amended at 74 FR 5090, Jan. 28, 2009]

§ 60.41c Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Clean Air Act and in subpart A of this part.

Annual capacity factor means the ratio between the actual heat input to a steam generating unit from an individual fuel or combination of fuels during a period of 12 consecutive calendar months and the potential heat input to the steam generating unit from all fuels had the steam generating unit been operated for 8,760 hours during that 12-month period at the maximum design heat input capacity. In the case of steam generating units that are rented or leased, the actual heat input shall be determined based on the combined heat input from all operations of the affected facility during a period of 12 consecutive calendar months.

Coal means all solid fuels classified as anthracite, bituminous, sub-bituminous, or lignite by the American Society of Testing and Materials in ASTM D388 (incorporated by reference, see §60.17), coal refuse, and petroleum coke. Coal-derived synthetic fuels derived from coal for the purposes of creating useful heat, including but not limited to solvent refined coal, gasified coal not meeting the definition of natural gas, coal-oil mixtures, and coal-water mixtures, are also included in this definition for the purposes of this subpart.

Coal refuse means any by-product of coal mining or coal cleaning operations with an ash content greater than 50 percent (by weight) and a heating value less than 13,900 kilojoules per kilogram (kJ/kg) (6,000 Btu per pound (Btu/lb) on a dry basis.

Cogeneration steam generating unit means a steam generating unit that simultaneously produces both electrical (or mechanical) and thermal energy from the same primary energy source.

Combined cycle system means a system in which a separate source (such as a stationary gas turbine, internal combustion engine, or kiln) provides exhaust gas to a steam generating unit.

Combustion research means the experimental firing of any fuel or combination of fuels in a steam generating unit for the purpose of conducting research and development of more efficient combustion or more effective prevention or control of air pollutant emissions from combustion, provided that, during these periods of research and development, the heat generated is not used for any purpose other than preheating combustion air for use by that steam generating unit (*i.e.* , the heat generated is released to the atmosphere without being used for space heating, process heating, driving pumps, preheating combustion air for other units, generating electricity, or any other purpose).

Conventional technology means wet flue gas desulfurization technology, dry flue gas desulfurization technology, atmospheric fluidized bed combustion technology, and oil hydrodesulfurization technology.

Distillate oil means fuel oil that complies with the specifications for fuel oil numbers 1 or 2, as defined by the American Society for Testing and Materials in ASTM D396 (incorporated by reference, see §60.17) or diesel fuel oil numbers 1 or 2, as defined by the American Society for Testing and Materials in ASTM D975 (incorporated by reference, see §60.17).

Dry flue gas desulfurization technology means a SO_2control system that is located between the steam generating unit and the exhaust vent or stack, and that removes sulfur oxides from the combustion gases of the steam generating unit by contacting the combustion gases with an alkaline reagent and water, whether introduced separately or as a premixed slurry or solution and forming a dry powder material. This definition includes devices where the dry powder material is subsequently converted to another form. Alkaline reagents used in dry flue gas desulfurization systems include, but are not limited to, lime and sodium compounds.

Duct burner means a device that combusts fuel and that is placed in the exhaust duct from another source (such as a stationary gas turbine, internal combustion engine, kiln, etc.) to allow the firing of additional fuel to heat the exhaust gases before the exhaust gases enter a steam generating unit.

Emerging technology means any SO_2control system that is not defined as a conventional technology under this section, and for which the owner or operator of the affected facility has received approval from the Administrator to operate as an emerging technology under §60.48c(a)(4).

Federally enforceable means all limitations and conditions that are enforceable by the Administrator, including the requirements of 40 CFR parts 60 and 61, requirements within any applicable State implementation plan, and any permit requirements established under 40 CFR 52.21 or under 40 CFR 51.18 and 51.24.

Fluidized bed combustion technology means a device wherein fuel is distributed onto a bed (or series of beds) of limestone aggregate (or other sorbent materials) for combustion; and these materials are forced upward in the device by the flow of combustion air and the gaseous products of combustion. Fluidized bed combustion technology includes, but is not limited to, bubbling bed units and circulating bed units.

Fuel pretreatment means a process that removes a portion of the sulfur in a fuel before combustion of the fuel in a steam generating unit.

Heat input means heat derived from combustion of fuel in a steam generating unit and does not include the heat derived from preheated combustion air, recirculated flue gases, or exhaust gases from other sources (such as stationary gas turbines, internal combustion engines, and kilns).

Heat transfer medium means any material that is used to transfer heat from one point to another point.

Maximum design heat input capacity means the ability of a steam generating unit to combust a stated maximum amount of fuel (or combination of fuels) on a steady state basis as determined by the physical design and characteristics of the steam generating unit.

Natural gas means:

(1) A naturally occurring mixture of hydrocarbon and nonhydrocarbon gases found in geologic formations beneath the earth's surface, of which the principal constituent is methane; or

(2) Liquefied petroleum (LP) gas, as defined by the American Society for Testing and Materials in ASTM D1835 (incorporated by reference, see §60.17); or

(3) A mixture of hydrocarbons that maintains a gaseous state at ISO conditions. Additionally, natural gas must either be composed of at least 70 percent methane by volume or have a gross calorific value between 34 and 43 megajoules (MJ) per dry standard cubic meter (910 and 1,150 Btu per dry standard cubic foot).

Noncontinental area means the State of Hawaii, the Virgin Islands, Guam, American Samoa, the Commonwealth of Puerto Rico, or the Northern Mariana Islands.

Oil means crude oil or petroleum, or a liquid fuel derived from crude oil or petroleum, including distillate oil and residual oil.

Potential sulfur dioxide emission rate means the theoretical SO_2emissions (nanograms per joule (ng/J) or lb/MMBtu heat input) that would result from combusting fuel in an uncleaned state and without using emission control systems.

Process heater means a device that is primarily used to heat a material to initiate or promote a chemical reaction in which the material participates as a reactant or catalyst.

Residual oil means crude oil, fuel oil that does not comply with the specifications under the definition of distillate oil, and all fuel oil numbers 4, 5, and 6, as defined by the American Society for Testing and Materials in ASTM D396 (incorporated by reference, see §60.17).

Steam generating unit means a device that combusts any fuel and produces steam or heats water or heats any heat transfer medium. This term includes any duct burner that combusts fuel and is part of a combined cycle system. This term does not include process heaters as defined in this subpart.

Steam generating unit operating day means a 24-hour period between 12:00 midnight and the following midnight during which any fuel is combusted at any time in the steam generating unit. It is not necessary for fuel to be combusted continuously for the entire 24-hour period.

Wet flue gas desulfurization technology means an SO_2 control system that is located between the steam generating unit and the exhaust vent or stack, and that removes sulfur oxides from the combustion gases of the steam generating unit by contacting the combustion gases with an alkaline slurry or solution and forming a liquid material. This definition includes devices where the liquid material is subsequently converted to another form. Alkaline reagents used in wet flue gas desulfurization systems include, but are not limited to, lime, limestone, and sodium compounds.

Wet scrubber system means any emission control device that mixes an aqueous stream or slurry with the exhaust gases from a steam generating unit to control emissions of PM or SO_2.

Wood means wood, wood residue, bark, or any derivative fuel or residue thereof, in any form, including but not limited to sawdust, sander dust, wood chips, scraps, slabs, millings, shavings, and processed pellets made from wood or other forest residues.

[72 FR 32759, June 13, 2007, as amended at 74 FR 5090, Jan. 28, 2009]

§ 60.42c Standard for sulfur dioxide (SO_2).

(a) Except as provided in paragraphs (b), (c), and (e) of this section, on and after the date on which the performance test is completed or required to be completed under §60.8, whichever date comes first, the owner or operator of an affected facility that combusts only coal shall neither: cause to be discharged into the atmosphere from the affected facility any gases that contain SO_2in excess of 87 ng/J (0.20 lb/MMBtu) heat input or 10 percent (0.10) of the potential SO_2emission rate (90 percent reduction), nor cause to be discharged into the atmosphere from the affected facility any gases that contain SO_2in excess of 520 ng/J (1.2 lb/MMBtu) heat input. If coal is combusted with other fuels, the affected facility shall neither: cause to be discharged into the atmosphere from the affected facility any gases that contain SO_2in excess of 87 ng/J (0.20 lb/MMBtu) heat input or 10 percent (0.10) of the potential SO_2emission rate (90 percent reduction), nor cause to be discharged into the atmosphere from the affected facility any gases that contain SO_2in excess of the emission limit is determined pursuant to paragraph (e)(2) of this section.

(b) Except as provided in paragraphs (c) and (e) of this section, on and after the date on which the performance test is completed or required to be completed under §60.8, whichever date comes first, the owner or operator of an affected facility that:

> (1) Combusts only coal refuse alone in a fluidized bed combustion steam generating unit shall neither:
>
> > (i) Cause to be discharged into the atmosphere from that affected facility any gases that contain SO_2in excess of 87 ng/J (0.20 lb/MMBtu) heat input or 20 percent (0.20) of the potential SO_2emission rate (80 percent reduction); nor
> >
> > (ii) Cause to be discharged into the atmosphere from that affected facility any gases that contain SO_2in excess of SO_2in excess of 520 ng/J (1.2 lb/MMBtu) heat input. If coal is fired with coal refuse, the affected facility subject to paragraph (a) of this section. If oil or any other fuel (except coal) is fired with coal refuse, the affected facility is subject to the

87 ng/J (0.20 lb/MMBtu) heat input SO_2 emissions limit or the 90 percent SO_2 reduction requirement specified in paragraph (a) of this section and the emission limit is determined pursuant to paragraph (e)(2) of this section.

(2) Combusts only coal and that uses an emerging technology for the control of SO_2 emissions shall neither:

(i) Cause to be discharged into the atmosphere from that affected facility any gases that contain SO_2 in excess of 50 percent (0.50) of the potential SO_2 emission rate (50 percent reduction); nor

(ii) Cause to be discharged into the atmosphere from that affected facility any gases that contain SO_2 in excess of 260 ng/J (0.60 lb/MMBtu) heat input. If coal is combusted with other fuels, the affected facility is subject to the 50 percent SO_2 reduction requirement specified in this paragraph and the emission limit determined pursuant to paragraph (e)(2) of this section.

(c) On and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that combusts coal, alone or in combination with any other fuel, and is listed in paragraphs (c)(1), (2), (3), or (4) of this section shall cause to be discharged into the atmosphere from that affected facility any gases that contain SO_2 in excess of the emission limit determined pursuant to paragraph (e)(2) of this section. Percent reduction requirements are not applicable to affected facilities under paragraphs (c)(1), (2), (3), or (4).

(1) Affected facilities that have a heat input capacity of 22 MW (75 MMBtu/hr) or less.

(2) Affected facilities that have an annual capacity for coal of 55 percent (0.55) or less and are subject to a federally enforceable requirement limiting operation of the affected facility to an annual capacity factor for coal of 55 percent (0.55) or less.

(3) Affected facilities located in a noncontinental area.

(4) Affected facilities that combust coal in a duct burner as part of a combined cycle system where 30 percent (0.30) or less of the heat entering the steam generating unit is from combustion of coal in the duct burner and 70 percent (0.70) or more of the heat entering the steam generating unit is from exhaust gases entering the duct burner.

(d) On and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that combusts oil shall cause to be discharged into the atmosphere from that affected facility any gases that contain SO_2 in excess of 215 ng/J (0.50 lb/MMBtu) heat input; or, as an alternative, no owner or operator of an affected facility that combusts oil shall combust oil in the affected facility that contains greater than 0.5 weight percent sulfur. The percent reduction requirements are not applicable to affected facilities under this paragraph.

(e) On and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that combusts coal, oil, or coal and oil with any other fuel shall cause to be discharged into the atmosphere from that affected facility any gases that contain SO_2 in excess of the following:

(1) The percent of potential SO_2 emission rate or numerical SO_2 emission rate required under paragraph (a) or (b)(2) of this section, as applicable, for any affected facility that

(i) Combusts coal in combination with any other fuel;

(ii) Has a heat input capacity greater than 22 MW (75 MMBtu/hr); and

(iii) Has an annual capacity factor for coal greater than 55 percent (0.55); and

(2) The emission limit determined according to the following formula for any affected facility that combusts coal, oil, or coal and oil with any other fuel:

$$E_s = \frac{(K_a H_a + K_b H_b + K_c H_c)}{(H_a + H_b + H_c)}$$

Where:

E_S= SO_2 emission limit, expressed in ng/J or lb/MMBtu heat input;

K_a= 520 ng/J (1.2 lb/MMBtu);

K_b= 260 ng/J (0.60 lb/MMBtu);

K_c= 215 ng/J (0.50 lb/MMBtu);

H_a= Heat input from the combustion of coal, except coal combusted in an affected facility subject to paragraph (b)(2) of this section, in Joules (J) [MMBtu];

H_b= Heat input from the combustion of coal in an affected facility subject to paragraph (b)(2) of this section, in J (MMBtu); and

H_c= Heat input from the combustion of oil, in J (MMBtu).

(f) Reduction in the potential SO_2emission rate through fuel pretreatment is not credited toward the percent reduction requirement under paragraph (b)(2) of this section unless:

(1) Fuel pretreatment results in a 50 percent (0.50) or greater reduction in the potential SO_2emission rate; and

(2) Emissions from the pretreated fuel (without either combustion or post-combustion SO_2control) are equal to or less than the emission limits specified under paragraph (b)(2) of this section.

(g) Except as provided in paragraph (h) of this section, compliance with the percent reduction requirements, fuel oil sulfur limits, and emission limits of this section shall be determined on a 30-day rolling average basis.

(h) For affected facilities listed under paragraphs (h)(1), (2), or (3) of this section, compliance with the emission limits or fuel oil sulfur limits under this section may be determined based on a certification from the fuel supplier, as described under §60.48c(f), as applicable.

(1) Distillate oil-fired affected facilities with heat input capacities between 2.9 and 29 MW (10 and 100 MMBtu/hr).

(2) Residual oil-fired affected facilities with heat input capacities between 2.9 and 8.7 MW (10 and 30 MMBtu/hr).

(3) Coal-fired facilities with heat input capacities between 2.9 and 8.7 MW (10 and 30 MMBtu/hr).

(i) The SO_2emission limits, fuel oil sulfur limits, and percent reduction requirements under this section apply at all times, including periods of startup, shutdown, and malfunction.

(j) For affected facilities located in noncontinental areas and affected facilities complying with the percent reduction standard, only the heat input supplied to the affected facility from the combustion of coal and oil is counted under this section. No credit is provided for the heat input to the affected facility from wood or other fuels or for heat derived from exhaust gases from other sources, such as stationary gas turbines, internal combustion engines, and kilns.

[72 FR 32759, June 13, 2007, as amended at 74 FR 5090, Jan. 28, 2009]

§ 60.43c Standard for particulate matter (PM).

(a) On and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification on or before February 28, 2005, that combusts coal or combusts mixtures of coal with other fuels and has a heat input capacity of 8.7 MW (30 MMBtu/hr) or greater, shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of the following emission limits:

(1) 22 ng/J (0.051 lb/MMBtu) heat input if the affected facility combusts only coal, or combusts coal with other fuels and has an annual capacity factor for the other fuels of 10 percent (0.10) or less.

(2) 43 ng/J (0.10 lb/MMBtu) heat input if the affected facility combusts coal with other fuels, has an annual capacity factor for the other fuels greater than 10 percent (0.10), and is subject to a federally enforceable requirement limiting operation of the affected facility to an annual capacity factor greater than 10 percent (0.10) for fuels other than coal.

(b) On and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification on or before February 28, 2005, that combusts wood or combusts mixtures of wood with other fuels (except coal) and has a heat input capacity of 8.7 MW (30 MMBtu/hr) or greater, shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of the following emissions limits:

(1) 43 ng/J (0.10 lb/MMBtu) heat input if the affected facility has an annual capacity factor for wood greater than 30 percent (0.30); or

(2) 130 ng/J (0.30 lb/MMBtu) heat input if the affected facility has an annual capacity factor for wood of 30 percent (0.30) or less and is subject to a federally enforceable requirement limiting operation of the affected facility to an annual capacity factor for wood of 30 percent (0.30) or less.

(c) On and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that can combust coal, wood, or oil and has a heat input capacity of 8.7 MW (30 MMBtu/hr) or greater shall cause to be discharged into the atmosphere from that affected facility any gases that exhibit greater than 20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity.

Owners and operators of an affected facility that elect to install, calibrate, maintain, and operate a continuous emissions monitoring system (CEMS) for measuring PM emissions according to the requirements of this subpart and are subject to a federally enforceable PM limit of 0.030 lb/MMBtu or less are exempt from the opacity standard specified in this paragraph.

(d) The PM and opacity standards under this section apply at all times, except during periods of startup, shutdown, or malfunction.

(e)

(1) On and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that commences construction, reconstruction, or modification after February 28, 2005, and that combusts coal, oil, wood, a mixture of these fuels, or a mixture of these fuels with any other fuels and has a heat input capacity of 8.7 MW (30 MMBtu/hr) or greater shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of 13 ng/J (0.030 lb/MMBtu) heat input, except as provided in paragraphs (e)(2), (e)(3), and (e)(4) of this section.

(2) As an alternative to meeting the requirements of paragraph (e)(1) of this section, the owner or operator of an affected facility for which modification commenced after February 28, 2005, may elect to meet the requirements of this paragraph. On and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that commences modification after February 28, 2005 shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of both:

(i) 22 ng/J (0.051 lb/MMBtu) heat input derived from the combustion of coal, oil, wood, a mixture of these fuels, or a mixture of these fuels with any other fuels; and

(ii) 0.2 percent of the combustion concentration (99.8 percent reduction) when combusting coal, oil, wood, a mixture of these fuels, or a mixture of these fuels with any other fuels.

(3) On and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that commences modification after February 28, 2005, and that combusts over 30 percent wood (by heat input) on an annual basis and has a heat input capacity of 8.7 MW (30 MMBtu/hr) or greater shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of 43 ng/J (0.10 lb/MMBtu) heat input.

(4) On and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, an owner or operator of an affected facility that commences construction, reconstruction, or modification after February 28, 2005, and that combusts only oil that contains no more than 0.50 weight percent sulfur or a mixture of 0.50 weight percent sulfur oil with other fuels not subject to a PM standard under §60.43c and not using a post-combustion technology (except a wet scrubber) to reduce PM or SO_2emissions is not subject to the PM limit in this section.

[72 FR 32759, June 13, 2007, as amended at 74 FR 5091, Jan. 28, 2009]

§ 60.44c Compliance and performance test methods and procedures for sulfur dioxide.

(a) Except as provided in paragraphs (g) and (h) of this section and §60.8(b), performance tests required under §60.8 shall be conducted following the procedures specified in paragraphs (b), (c), (d), (e), and (f) of this section, as applicable. Section 60.8(f) does not apply to this section. The 30-day notice required in §60.8(d) applies only to the initial performance test unless otherwise specified by the Administrator.

(b) The initial performance test required under §60.8 shall be conducted over 30 consecutive operating days of the steam generating unit. Compliance with the percent reduction requirements and SO_2emission limits under §60.42c shall be determined using a 30-day average. The first operating day included in the initial performance test shall be scheduled within 30 days after achieving the maximum production rate at which the affect facility will be operated, but not later than 180 days after the initial startup of the facility. The steam generating unit load during the 30-day period does not have to be the maximum design heat input capacity, but must be representative of future operating conditions.

(c) After the initial performance test required under paragraph (b) of this section and §60.8, compliance with the percent reduction requirements and SO_2emission limits under §60.42c is based on the average percent reduction and the average SO_2emission rates for 30 consecutive steam generating unit operating days. A separate performance test is completed at the end of each steam generating unit operating day, and a new 30-day average percent reduction and SO_2emission rate are calculated to show compliance with the standard.

(d) If only coal, only oil, or a mixture of coal and oil is combusted in an affected facility, the procedures in Method 19 of appendix A of this part are used to determine the hourly SO_2 emission rate (E_{ho}) and the 30-day average SO_2 emission rate (E_{ao}). The hourly averages used to compute the 30-day averages are obtained from the CEMS. Method 19 of appendix A of this part shall be used to calculate E_{ao} when using daily fuel sampling or Method 6B of appendix A of this part.

(e) If coal, oil, or coal and oil are combusted with other fuels:

(1) An adjusted E_{ho}(E_{ho}O) is used in Equation 19–19 of Method 19 of appendix A of this part to compute the adjusted E_{ao}(E_{ao}O). The E_{ho}O is computed using the following formula:

$$E_{ho}O = \frac{E_{ho} - E_w(1 - X_k)}{X_k}$$

Where:

E_{ho}O = Adjusted E_{ho}, ng/J (lb/MMBtu);

E_{ho}= Hourly SO_2 emission rate, ng/J (lb/MMBtu);

E_w= SO_2 concentration in fuels other than coal and oil combusted in the affected facility, as determined by fuel sampling and analysis procedures in Method 9 of appendix A of this part, ng/J (lb/MMBtu). The value E_w for each fuel lot is used for each hourly average during the time that the lot is being combusted. The owner or operator does not have to measure E_w if the owner or operator elects to assume E_w = 0.

X_k = Fraction of the total heat input from fuel combustion derived from coal and oil, as determined by applicable procedures in Method 19 of appendix A of this part.

(2) The owner or operator of an affected facility that qualifies under the provisions of §60.42c(c) or (d) (where percent reduction is not required) does not have to measure the parameters E_w or X_k if the owner or operator of the affected facility elects to measure emission rates of the coal or oil using the fuel sampling and analysis procedures under Method 19 of appendix A of this part.

(f) Affected facilities subject to the percent reduction requirements under §60.42c(a) or (b) shall determine compliance with the SO_2emission limits under §60.42c pursuant to paragraphs (d) or (e) of this section, and shall determine compliance with the percent reduction requirements using the following procedures:

(1) If only coal is combusted, the percent of potential SO_2 emission rate is computed using the following formula:

$$\%P_s = 100\left(1 - \frac{\%R_g}{100}\right)\left(1 - \frac{\%R_f}{100}\right)$$

Where:

$\%P_s$= Potential SO_2 emission rate, in percent;

$\%R_g$= SO_2 removal efficiency of the control device as determined by Method 19 of appendix A of this part, in percent; and

$\%R_f$= SO_2 removal efficiency of fuel pretreatment as determined by Method 19 of appendix A of this part, in percent.

(2) If coal, oil, or coal and oil are combusted with other fuels, the same procedures required in paragraph (f)(1) of this section are used, except as provided for in the following:

(i) To compute the $\%P_s$, an adjusted $\%R_g$($\%R_g$O) is computed from E_{ao}O from paragraph (e)(1) of this section and an adjusted average SO_2 inlet rate (E_{ai}O) using the following formula:

$$\%R_gO = 100\left(1 - \frac{E_{ao}^{o}}{E_{ai}^{o}}\right)$$

Where:

$\%R_g$O = Adjusted $\%R_g$, in percent;

E_{ao}O = Adjusted E_{ao}, ng/J (lb/MMBtu); and

E_{ai}O = Adjusted average SO_2 inlet rate, ng/J (lb/MMBtu).

(ii) To compute E_{ai}O, an adjusted hourly SO_2 inlet rate (E_{hi}O) is used. The E_{hi}O is computed using the following formula:

$$E_{hi}O = \frac{E_{hi} - E_w(1 - X_1)}{X_1}$$

Where:

$E_{hi}O$ = Adjusted E_{hi}, ng/J (lb/MMBtu);

E_{hi}= Hourly SO_2inlet rate, ng/J (lb/MMBtu);

E_W= SO_2 concentration in fuels other than coal and oil combusted in the affected facility, as determined by fuel sampling and analysis procedures in Method 19 of appendix A of this part, ng/J (lb/MMBtu). The value E_W for each fuel lot is used for each hourly average during the time that the lot is being combusted. The owner or operator does not have to measure E_W if the owner or operator elects to assume E_W= 0; and

X_K= Fraction of the total heat input from fuel combustion derived from coal and oil, as determined by applicable procedures in Method 19 of appendix A of this part.

(g) For oil-fired affected facilities where the owner or operator seeks to demonstrate compliance with the fuel oil sulfur limits under §60.42c based on shipment fuel sampling, the initial performance test shall consist of sampling and analyzing the oil in the initial tank of oil to be fired in the steam generating unit to demonstrate that the oil contains 0.5 weight percent sulfur or less. Thereafter, the owner or operator of the affected facility shall sample the oil in the fuel tank after each new shipment of oil is received, as described under §60.46c(d)(2).

(h) For affected facilities subject to §60.42c(h)(1), (2), or (3) where the owner or operator seeks to demonstrate compliance with the SO_2standards based on fuel supplier certification, the performance test shall consist of the certification from the fuel supplier, as described in §60.48c(f), as applicable.

(i) The owner or operator of an affected facility seeking to demonstrate compliance with the SO_2 standards under §60.42c(c)(2) shall demonstrate the maximum design heat input capacity of the steam generating unit by operating the steam generating unit at this capacity for 24 hours. This demonstration shall be made during the initial performance test, and a subsequent demonstration may be requested at any other time. If the demonstrated 24-hour average firing rate for the affected facility is less than the maximum design heat input capacity stated by the manufacturer of the affected facility, the demonstrated 24-hour average firing rate shall be used to determine the annual capacity factor for the affected facility; otherwise, the maximum design heat input capacity provided by the manufacturer shall be used.

(j) The owner or operator of an affected facility shall use all valid SO_2 emissions data in calculating $\%P_S$ and E_{ho} under paragraphs (d), (e), or (f) of this section, as applicable, whether or not the minimum emissions data requirements under §60.46c(f) are achieved. All valid emissions data, including valid data collected during periods of startup, shutdown, and malfunction, shall be used in calculating $\%P_S$ or E_{ho} pursuant to paragraphs (d), (e), or (f) of this section, as applicable.

[72 FR 32759, June 13, 2007, as amended at 74 FR 5091, Jan. 28, 2009]

§ 60.45c Compliance and performance test methods and procedures for particulate matter.

(a) The owner or operator of an affected facility subject to the PM and/or opacity standards under §60.43c shall conduct an initial performance test as required under §60.8, and shall conduct subsequent performance tests as requested by the Administrator, to determine compliance with the standards using the following procedures and reference methods, except as specified in paragraph (c) of this section.

(1) Method 1 of appendix A of this part shall be used to select the sampling site and the number of traverse sampling points.

(2) Method 3A or 3B of appendix A–2 of this part shall be used for gas analysis when applying Method 5 or 5B of appendix A–3 of this part or 17 of appendix A–6 of this part.
(3) Method 5, 5B, or 17 of appendix A of this part shall be used to measure the concentration of PM as follows:

(i) Method 5 of appendix A of this part may be used only at affected facilities without wet scrubber systems.

(ii) Method 17 of appendix A of this part may be used at affected facilities with or without wet scrubber systems provided the stack gas temperature does not exceed a temperature of 160 °C (320 °F). The procedures of Sections 8.1 and 11.1 of Method 5B of appendix A of this part may be used in Method 17 of appendix A of this part only if Method 17 of appendix A of this part is used in conjunction with a wet scrubber system. Method 17 of appendix A of this part shall not be used in conjunction with a wet scrubber system if the effluent is saturated or laden with water droplets.

(iii) Method 5B of appendix A of this part may be used in conjunction with a wet scrubber system.

(4) The sampling time for each run shall be at least 120 minutes and the minimum sampling volume shall be 1.7 dry standard cubic meters (dscm) [60 dry standard cubic feet (dscf)] except that smaller sampling times or volumes may be approved by the Administrator when necessitated by process variables or other factors.

(5) For Method 5 or 5B of appendix A of this part, the temperature of the sample gas in the probe and filter holder shall be monitored and maintained at 160 ±14 °C (320±25 °F).

(6) For determination of PM emissions, an oxygen (O_2) or carbon dioxide (CO_2) measurement shall be obtained simultaneously with each run of Method 5, 5B, or 17 of appendix A of this part by traversing the duct at the same sampling location.

(7) For each run using Method 5, 5B, or 17 of appendix A of this part, the emission rates expressed in ng/J (lb/MMBtu) heat input shall be determined using:

(i) The O_2or CO_2measurements and PM measurements obtained under this section, (ii) The dry basis F factor, and

(iii) The dry basis emission rate calculation procedure contained in Method 19 of appendix A of this part.

(8) Method 9 of appendix A–4 of this part shall be used for determining the opacity of stack emissions.

(b) The owner or operator of an affected facility seeking to demonstrate compliance with the PM standards under §60.43c(b)(2) shall demonstrate the maximum design heat input capacity of the steam generating unit by operating the steam generating unit at this capacity for 24 hours. This demonstration shall be made during the initial performance test, and a subsequent demonstration may be requested at any other time. If the demonstrated 24-hour average firing rate for the affected facility is less than the maximum design heat input capacity stated by the manufacturer of the affected facility, the demonstrated 24-hour average firing rate shall be used to determine the annual capacity factor for the affected facility; otherwise, the maximum design heat input capacity provided by the manufacturer shall be used.

(c) In place of PM testing with Method 5 or 5B of appendix A–3 of this part or Method 17 of appendix A–6 of this part, an owner or operator may elect to install, calibrate, maintain, and operate a CEMS for monitoring PM emissions discharged to the atmosphere and record the output of the system. The owner or operator of an affected facility who elects to continuously monitor PM emissions instead of conducting performance testing using Method 5 or 5B of appendix A–3 of this part or Method 17 of appendix A–6 of this part shall install, calibrate, maintain, and operate a CEMS and shall comply with the requirements specified in paragraphs (c)(1) through (c)(14) of this section.

(1) Notify the Administrator 1 month before starting use of the system.

(2) Notify the Administrator 1 month before stopping use of the system.

(3) The monitor shall be installed, evaluated, and operated in accordance with §60.13 of subpart A of this part.

(4) The initial performance evaluation shall be completed no later than 180 days after the date of initial startup of the affected facility, as specified under §60.8 of subpart A of this part or within 180 days of notification to the Administrator of use of CEMS if the owner or operator was previously determining compliance by Method 5, 5B, or 17 of appendix A of this part performance tests, whichever is later.

(5) The owner or operator of an affected facility shall conduct an initial performance test for PM emissions as required under §60.8 of subpart A of this part. Compliance with the PM emission limit shall be determined by using the CEMS specified in paragraph (d) of this section to measure PM and calculating a 24-hour block arithmetic average emission concentration using EPA Reference Method 19 of appendix A of this part, section 4.1.

(6) Compliance with the PM emission limit shall be determined based on the 24-hour daily (block) average of the hourly arithmetic average emission concentrations using CEMS outlet data.

(7) At a minimum, valid CEMS hourly averages shall be obtained as specified in paragraph (c)(7)(i) of this section for 75 percent of the total operating hours per 30-day rolling average.

(i) At least two data points per hour shall be used to calculate each 1-hour arithmetic average.

(ii) [Reserved]

(8) The 1-hour arithmetic averages required under paragraph (c)(7) of this section shall be expressed in ng/J or lb/MMBtu heat input and shall be used to calculate the boiler operating day daily arithmetic average emission concentrations. The 1-hour arithmetic averages shall be calculated using the data points required under §60.13(e)(2) of subpart A of this part.

(9) All valid CEMS data shall be used in calculating average emission concentrations even if the minimum CEMS data requirements of paragraph (c)(7) of this section are not met.

(10) The CEMS shall be operated according to Performance Specification 11 in appendix B of this part.

(11) During the correlation testing runs of the CEMS required by Performance Specification 11 in appendix B of this part, PM and O_2(or CO_2) data shall be collected concurrently (or within a 30- to 60-minute period) by both the continuous emission monitors and performance tests conducted using the following test methods.

(i) For PM, Method 5 or 5B of appendix A–3 of this part or Method 17 of appendix A–6 of this part shall be used; and

(ii) After July 1, 2010 or after Method 202 of appendix M of part 51 has been revised to minimize artifact measurement and notice of that change has been published in theFederal Register, whichever is later, for condensable PM emissions, Method 202 of appendix M of part 51 shall be used; and

(iii) For O2 (or CO_2), Method 3A or 3B of appendix A–2 of this part, as applicable shall be used.

(12) Quarterly accuracy determinations and daily calibration drift tests shall be performed in accordance with procedure 2 in appendix F of this part. Relative Response Audit's must be performed annually and Response Correlation Audits must be performed every 3 years.

(13) When PM emissions data are not obtained because of CEMS breakdowns, repairs, calibration checks, and zero and span adjustments, emissions data shall be obtained by using other monitoring systems as approved by the Administrator or EPA Reference Method 19 of appendix A of this part to provide, as necessary, valid emissions data for a minimum of 75 percent of total operating hours on a 30-day rolling average.

(14) After July 1, 2011, within 90 days after the date of completing each performance evaluation required by paragraph (c)(11) of this section, the owner or operator of the affected facility must either submit the test data to EPA by successfully entering the data electronically into EPA's WebFIRE data base available at *http://cfpub.epa.gov/oarweb/index.cfm?action=fire.main* or mail a copy to: United States Environmental Protection Agency; Energy Strategies Group; 109 TW Alexander DR; Mail Code: D243–01; RTP, NC 27711.

(d) The owner or operator of an affected facility seeking to demonstrate compliance under §60.43c(e)(4) shall follow the applicable procedures under §60.48c(f). For residual oil-fired affected facilities, fuel supplier certifications are only allowed for facilities with heat input capacities between 2.9 and 8.7 MW (10 to 30 MMBtu/hr).

[72 FR 32759, June 13, 2007, as amended at 74 FR 5091, Jan. 28, 2009]

§ 60.46c Emission monitoring for sulfur dioxide.

(a) Except as provided in paragraphs (d) and (e) of this section, the owner or operator of an affected facility subject to the SO_2emission limits under §60.42c shall install, calibrate, maintain, and operate a CEMS for measuring SO_2concentrations and either O_2or CO_2concentrations at the outlet of the SO_2control device (or the outlet of the steam generating unit if no SO_2control device is used), and shall record the output of the system. The owner or operator of an affected facility subject to the percent reduction requirements under §60.42c shall measure SO_2concentrations and either O_2or CO_2concentrations at both the inlet and outlet of the SO_2control device.

(b) The 1-hour average SO_2emission rates measured by a CEMS shall be expressed in ng/J or lb/MMBtu heat input and shall be used to calculate the average emission rates under §60.42c. Each 1-hour average SO_2emission rate must be based on at least 30 minutes of operation, and shall be calculated using the data points required under §60.13(h)(2). Hourly SO_2emission rates are not calculated if the affected facility is operated less than 30 minutes in a 1-hour period and are not counted toward determination of a steam generating unit operating day.

(c) The procedures under §60.13 shall be followed for installation, evaluation, and operation of the CEMS.

(1) All CEMS shall be operated in accordance with the applicable procedures under Performance Specifications 1, 2, and 3 of appendix B of this part.

(2) Quarterly accuracy determinations and daily calibration drift tests shall be performed in accordance with Procedure 1 of appendix F of this part.

(3) For affected facilities subject to the percent reduction requirements under §60.42c, the span value of the SO_2CEMS at the inlet to the SO_2control device shall be 125 percent of the maximum estimated hourly potential SO_2emission rate of the fuel combusted, and the span value of the SO_2CEMS at the outlet from the SO_2control device shall be 50 percent of the maximum estimated hourly potential SO_2emission rate of the fuel combusted.

(4) For affected facilities that are not subject to the percent reduction requirements of §60.42c, the span value of the SO_2CEMS at the outlet from the SO_2control device (or outlet of the steam generating unit if no SO_2control device is used) shall be 125 percent of the maximum estimated hourly potential SO_2emission rate of the fuel combusted.

(d) As an alternative to operating a CEMS at the inlet to the SO_2control device (or outlet of the steam generating unit if no SO_2control device is used) as required under paragraph (a) of this section, an owner or operator may elect to determine the average SO_2emission rate by sampling the fuel prior to combustion. As an alternative to operating a CEMS at the outlet from the SO_2control device (or outlet of the steam generating unit if no SO_2control device is used) as required under paragraph (a) of this section, an owner or operator may elect to determine the average SO_2emission rate by using Method 6B of appendix A of this part. Fuel sampling shall be conducted pursuant to either paragraph (d)(1) or (d)(2) of this section. Method 6B of appendix A of this part shall be conducted pursuant to paragraph (d)(3) of this section.

(1) For affected facilities combusting coal or oil, coal or oil samples shall be collected daily in an as-fired condition at the inlet to the steam generating unit and analyzed for sulfur content and heat content according the Method 19 of appendix A of this part. Method 19 of appendix A of this part provides procedures for converting these measurements into the format to be used in calculating the average SO_2input rate.

(2) As an alternative fuel sampling procedure for affected facilities combusting oil, oil samples may be collected from the fuel tank for each steam generating unit immediately after the fuel tank is filled and before any oil is combusted. The owner or operator of the affected facility shall analyze the oil sample to determine the sulfur content of the oil. If a partially empty fuel tank is refilled, a new sample and analysis of the fuel in the tank would be required upon filling. Results of the fuel analysis taken after each new shipment of oil is received shall be used as the daily value when calculating the 30-day rolling average until the next shipment is received. If the fuel analysis shows that the sulfur content in the fuel tank is greater than 0.5 weight percent sulfur, the owner or operator shall ensure that the sulfur content of subsequent oil shipments is low enough to cause the 30-day rolling average sulfur content to be 0.5 weight percent sulfur or less.

(3) Method 6B of appendix A of this part may be used in lieu of CEMS to measure SO_2at the inlet or outlet of the SO_2control system. An initial stratification test is required to verify the adequacy of the Method 6B of appendix A of this part sampling location. The stratification test shall consist of three paired runs of a suitable $SO_2$and CO_2measurement train operated at the candidate location and a second similar train operated according to the procedures in §3.2 and the applicable procedures in section 7 of Performance Specification 2 of appendix B of this part. Method 6B of appendix A of this part, Method 6A of appendix A of this part, or a combination of Methods 6 and 3 of appendix A of this part or Methods 6C and 3A of appendix A of this part are suitable measurement techniques. If Method 6B of appendix A of this part is used for the second train, sampling time and timer operation may be adjusted for the stratification test as long as an adequate sample volume is collected; however, both sampling trains are to be operated similarly. For the location to be adequate for Method 6B of appendix A of this part 24-hour tests, the mean of the absolute difference between the three paired runs must be less than 10 percent (0.10).

(e) The monitoring requirements of paragraphs (a) and (d) of this section shall not apply to affected facilities subject to §60.42c(h) (1), (2), or (3) where the owner or operator of the affected facility seeks to demonstrate compliance with the SO_2standards based on fuel supplier certification, as described under §60.48c(f), as applicable.

(f) The owner or operator of an affected facility operating a CEMS pursuant to paragraph (a) of this section, or conducting as-fired fuel sampling pursuant to paragraph (d)(1) of this section, shall obtain emission data for at least 75 percent of the operating hours in at least 22 out of 30 successive steam generating unit operating days. If this minimum data requirement is not met with a single monitoring system, the owner or operator of the affected facility shall supplement the emission data with data collected with other monitoring systems as approved by the Administrator.

§ 60.47c Emission monitoring for particulate matter.

(a) Except as provided in paragraphs (c), (d), (e), (f), and (g) of this section, the owner or operator of an affected facility combusting coal, oil, or wood that is subject to the opacity standards under §60.43c shall install, calibrate, maintain, and operate a continuous opacity monitoring system (COMS) for measuring the opacity of the emissions discharged to the atmosphere and record the output of the system. The owner or operator of an affected facility subject to an opacity standard in §60.43c(c) and that is not required to install a COMS due to paragraphs (c), (d), (e), or (f) of this section that elects not to install a COMS shall conduct a performance test using Method 9 of appendix A–4 of this part and the procedures in §60.11 to demonstrate compliance with the applicable limit in §60.43c and shall comply with either paragraphs (a)(1), (a)(2), or (a)(3) of this section. If during the initial 60 minutes of observation all 6-minute averages are less than 10 percent and all individual 15-second observations are less than or equal to 20 percent, the observation period may be reduced from 3 hours to 60 minutes.

(1) Except as provided in paragraph (a)(2) and (a)(3) of this section, the owner or operator shall conduct subsequent Method 9 of appendix A–4 of this part performance tests using the procedures in paragraph (a) of this section according to the applicable schedule in paragraphs (a)(1)(i) through (a)(1)(iv) of this section, as determined by the most recent Method 9 of appendix A–4 of this part performance test results.

(i) If no visible emissions are observed, a subsequent Method 9 of appendix A–4 of this part performance test must be completed within 12 calendar months from the date that the most recent performance test was conducted;

(ii) If visible emissions are observed but the maximum 6-minute average opacity is less than or equal to 5 percent, a subsequent Method 9 of appendix A–4 of this part performance test must be completed within 6 calendar months from the date that the most recent performance test was conducted;

(iii) If the maximum 6-minute average opacity is greater than 5 percent but less than or equal to 10 percent, a subsequent Method 9 of appendix A–4 of this part performance test must be completed within 3 calendar months from the date that the most recent performance test was conducted; or

(iv) If the maximum 6-minute average opacity is greater than 10 percent, a subsequent Method 9 of appendix A–4 of this part performance test must be completed within 30 calendar days from the date that the most recent performance test was conducted.

(2) If the maximum 6-minute opacity is less than 10 percent during the most recent Method 9 of appendix A–4 of this part performance test, the owner or operator may, as an alternative to performing subsequent Method 9 of appendix A–4 of this part performance tests, elect to perform subsequent monitoring using Method 22 of appendix A–7 of this part according to the procedures specified in paragraphs (a)(2)(i) and (ii) of this section.

(i) The owner or operator shall conduct 10 minute observations (during normal operation) each operating day the affected facility fires fuel for which an opacity standard is applicable using Method 22 of appendix A–7 of this part and demonstrate that the sum of the occurrences of any visible emissions is not in excess of 5 percent of the observation period (*i.e.* , 30 seconds per 10 minute period). If the sum of the occurrence of any visible emissions is greater than 30 seconds during the initial 10 minute observation, immediately conduct a 30 minute observation. If the sum of the occurrence of visible emissions is greater than 5 percent of the observation period (*i.e.* , 90 seconds per 30 minute period) the owner or operator shall either document and adjust the operation of the facility and demonstrate within 24 hours that the sum of the occurrence of visible emissions is equal to or less than 5 percent during a 30 minute observation (*i.e.* , 90 seconds) or conduct a new Method 9 of appendix A–4 of this part performance test using the procedures in paragraph (a) of this section within 30 calendar days according to the requirements in §60.45c(a)(8).

(ii) If no visible emissions are observed for 30 operating days during which an opacity standard is applicable, observations can be reduced to once every 7 operating days during which an opacity standard is applicable. If any visible emissions are observed, daily observations shall be resumed.

(3) If the maximum 6-minute opacity is less than 10 percent during the most recent Method 9 of appendix A–4 of this part performance test, the owner or operator may, as an alternative to performing subsequent Method 9 of appendix A–4 performance tests, elect to perform subsequent monitoring using a digital opacity compliance system according to a site-specific monitoring plan approved by the Administrator. The observations shall be similar, but not necessarily identical, to the requirements in paragraph (a)(2) of this section. For reference purposes in preparing the monitoring plan, see OAQPS “Determination of Visible Emission Opacity from Stationary Sources Using Computer-Based Photographic Analysis Systems.” This document is available from the U.S. Environmental Protection Agency (U.S. EPA); Office of Air Quality and Planning Standards; Sector Policies and Programs Division; Measurement Policy Group (D243–02), Research Triangle Park, NC 27711. This document is also available on the Technology Transfer Network (TTN) under Emission Measurement Center Preliminary Methods.

(b) All COMS shall be operated in accordance with the applicable procedures under Performance Specification 1 of appendix B of this part. The span value of the opacity COMS shall be between 60 and 80 percent.

(c) Owners and operators of an affected facilities that burn only distillate oil that contains no more than 0.5 weight percent sulfur and/or liquid or gaseous fuels with potential sulfur dioxide emission rates of 26 ng/J (0.060 lb/MMBtu) heat input or less and that do not use a post-combustion technology to reduce SO2 or PM emissions and that are subject to an opacity standard in §60.43c(c) are not required to operate a COMS if they follow the applicable procedures in §60.48c(f).

(d) Owners or operators complying with the PM emission limit by using a PM CEMS must calibrate, maintain, operate, and record the output of the system for PM emissions discharged to the atmosphere as specified in §60.45c(c). The CEMS specified in paragraph §60.45c(c) shall be operated and data recorded during all periods of operation of the affected facility except for CEMS breakdowns and repairs. Data is recorded during calibration checks, and zero and span adjustments.

(e) Owners and operators of an affected facility that is subject to an opacity standard in §60.43c(c) and that does not use post-combustion technology (except a wet scrubber) for reducing PM, SO_2, or carbon monoxide (CO) emissions, burns only gaseous fuels or fuel oils that contain less than or equal to 0.5 weight percent sulfur, and is operated such that emissions of CO discharged to the atmosphere from the affected facility are maintained at levels less than or equal to 0.15 lb/MMBtu on a boiler operating day average basis is not required to operate a COMS. Owners and operators of affected facilities electing to comply with this paragraph must demonstrate compliance according to the procedures specified in paragraphs (e)(1) through (4) of this section; or

(1) You must monitor CO emissions using a CEMS according to the procedures specified in paragraphs (e)(1)(i) through (iv) of this section.

(i) The CO CEMS must be installed, certified, maintained, and operated according to the provisions in §60.58b(i)(3) of subpart Eb of this part.

(ii) Each 1-hour CO emissions average is calculated using the data points generated by the CO CEMS expressed in parts per million by volume corrected to 3 percent oxygen (dry basis).

(iii) At a minimum, valid 1-hour CO emissions averages must be obtained for at least 90 percent of the operating hours on a 30-day rolling average basis. The 1-hour averages are calculated using the data points required in §60.13(h)(2).

(iv) Quarterly accuracy determinations and daily calibration drift tests for the CO CEMS must be performed in accordance with procedure 1 in appendix F of this part.

(2) You must calculate the 1-hour average CO emissions levels for each steam generating unit operating day by multiplying the average hourly CO output concentration measured by the CO CEMS times the corresponding average hourly flue gas flow rate and divided by the corresponding average hourly heat input to the affected source. The 24-hour average CO emission level is determined by calculating the arithmetic average of the hourly CO emission levels computed for each steam generating unit operating day.

(3) You must evaluate the preceding 24-hour average CO emission level each steam generating unit operating day excluding periods of affected source startup, shutdown, or malfunction. If the 24-hour average CO emission level is greater than 0.15 lb/MMBtu, you must initiate investigation of the relevant equipment and control systems within 24 hours of the first discovery of the high emission incident and, take the appropriate corrective action as soon as practicable to adjust control settings or repair equipment to reduce the 24-hour average CO emission level to 0.15 lb/MMBtu or less.

(4) You must record the CO measurements and calculations performed according to paragraph (e) of this section and any corrective actions taken. The record of corrective action taken must include the date and time during which the 24-hour average CO emission level was greater than 0.15 lb/MMBtu, and the date, time, and description of the corrective action.

(f) Owners and operators of an affected facility that is subject to an opacity standard in §60.43c(c) and that uses a bag leak detection system to monitor the performance of a fabric filter (baghouse) according to the most recent requirements in section §60.48Da of this part is not required to operate a COMS.

(g) Owners and operators of an affected facility that is subject to an opacity standard in §60.43c(c) and that burns only gaseous fuels or fuel oils that contain less than or equal to 0.5 weight percent sulfur and operates according to a written site-specific monitoring plan approved by the permitting authority is not required to operate a COMS. This monitoring plan must include procedures and criteria for establishing and monitoring specific parameters for the affected facility indicative of compliance with the opacity standard.

[72 FR 32759, June 13, 2007, as amended at 74 FR 5091, Jan. 28, 2009]

§ 60.48c Reporting and recordkeeping requirements.

(a) The owner or operator of each affected facility shall submit notification of the date of construction or reconstruction and actual startup, as provided by §60.7 of this part. This notification shall include:

(1) The design heat input capacity of the affected facility and identification of fuels to be combusted in the affected facility.

(2) If applicable, a copy of any federally enforceable requirement that limits the annual capacity factor for any fuel or mixture of fuels under §60.42c, or §60.43c.

(3) The annual capacity factor at which the owner or operator anticipates operating the affected facility based on all fuels fired and based on each individual fuel fired.

(4) Notification if an emerging technology will be used for controlling SO_2emissions. The Administrator will examine the description of the control device and will determine whether the technology qualifies as an emerging technology. In making this determination, the Administrator may require the owner or operator of the affected facility to submit additional information concerning the control device. The affected facility is subject to the provisions of §60.42c(a) or (b)(1), unless and until this determination is made by the Administrator.

(b) The owner or operator of each affected facility subject to the SO_2emission limits of §60.42c, or the PM or opacity limits of §60.43c, shall submit to the Administrator the performance test data from the initial and any subsequent performance tests and, if applicable, the performance evaluation of the CEMS and/or COMS using the applicable performance specifications in appendix B of this part.

(c) In addition to the applicable requirements in §60.7, the owner or operator of an affected facility subject to the opacity limits in §60.43c(c) shall submit excess emission reports for any excess emissions from the affected facility that occur during the reporting period and maintain records according to the requirements specified in paragraphs (c)(1) through (3) of this section, as applicable to the visible emissions monitoring method used.

(1) For each performance test conducted using Method 9 of appendix A–4 of this part, the owner or operator shall keep the records including the information specified in paragraphs (c)(1)(i) through (iii) of this section.

(i) Dates and time intervals of all opacity observation periods;

(ii) Name, affiliation, and copy of current visible emission reading certification for each visible emission observer participating in the performance test; and

(iii) Copies of all visible emission observer opacity field data sheets;

(2) For each performance test conducted using Method 22 of appendix A–4 of this part, the owner or operator shall keep the records including the information specified in paragraphs (c)(2)(i) through (iv) of this section.

(i) Dates and time intervals of all visible emissions observation periods;

(ii) Name and affiliation for each visible emission observer participating in the performance test;

(iii) Copies of all visible emission observer opacity field data sheets; and

(iv) Documentation of any adjustments made and the time the adjustments were completed to the affected facility operation by the owner or operator to demonstrate compliance with the applicable monitoring requirements.

(3) For each digital opacity compliance system, the owner or operator shall maintain records and submit reports according to the requirements specified in the site-specific monitoring plan approved by the Administrator

(d) The owner or operator of each affected facility subject to the SO_2emission limits, fuel oil sulfur limits, or percent reduction requirements under §60.42c shall submit reports to the Administrator.

(e) The owner or operator of each affected facility subject to the SO_2emission limits, fuel oil sulfur limits, or percent reduction requirements under §60.42c shall keep records and submit reports as required under paragraph (d) of this section, including the following information, as applicable.

(1) Calendar dates covered in the reporting period.

(2) Each 30-day average SO_2emission rate (ng/J or lb/MMBtu), or 30-day average sulfur content (weight percent), calculated during the reporting period, ending with the last 30-day period; reasons for any noncompliance with the emission standards; and a description of corrective actions taken.

(3) Each 30-day average percent of potential SO_2emission rate calculated during the reporting period, ending with the last 30-day period; reasons for any noncompliance with the emission standards; and a description of the corrective actions taken.

(4) Identification of any steam generating unit operating days for which SO_2or diluent (O_2or CO_2) data have not been obtained by an approved method for at least 75 percent of the operating hours; justification for not obtaining sufficient data; and a description of corrective actions taken.

(5) Identification of any times when emissions data have been excluded from the calculation of average emission rates; justification for excluding data; and a description of corrective actions taken if data have been excluded for periods other than those during which coal or oil were not combusted in the steam generating unit.

(6) Identification of the F factor used in calculations, method of determination, and type of fuel combusted.

(7) Identification of whether averages have been obtained based on CEMS rather than manual sampling methods.

(8) If a CEMS is used, identification of any times when the pollutant concentration exceeded the full span of the CEMS.

(9) If a CEMS is used, description of any modifications to the CEMS that could affect the ability of the CEMS to comply with Performance Specifications 2 or 3 of appendix B of this part.

(10) If a CEMS is used, results of daily CEMS drift tests and quarterly accuracy assessments as required under appendix F, Procedure 1 of this part.

(11) If fuel supplier certification is used to demonstrate compliance, records of fuel supplier certification as described under paragraph (f)(1), (2), (3), or (4) of this section, as applicable. In addition to records of fuel supplier certifications, the report shall include a certified statement

signed by the owner or operator of the affected facility that the records of fuel supplier certifications submitted represent all of the fuel combusted during the reporting period.

(f) Fuel supplier certification shall include the following information:

(1) For distillate oil:

(i) The name of the oil supplier;

(ii) A statement from the oil supplier that the oil complies with the specifications under the definition of distillate oil in §60.41c; and

(iii) The sulfur content or maximum sulfur content of the oil.

(2) For residual oil:

(i) The name of the oil supplier;

(ii) The location of the oil when the sample was drawn for analysis to determine the sulfur content of the oil, specifically including whether the oil was sampled as delivered to the affected facility, or whether the sample was drawn from oil in storage at the oil supplier's or oil refiner's facility, or other location;

(iii) The sulfur content of the oil from which the shipment came (or of the shipment itself); and

(iv) The method used to determine the sulfur content of the oil.

(3) For coal:

(i) The name of the coal supplier;

(ii) The location of the coal when the sample was collected for analysis to determine the properties of the coal, specifically including whether the coal was sampled as delivered to the affected facility or whether the sample was collected from coal in storage at the mine, at a coal preparation plant, at a coal supplier's facility, or at another location. The certification shall include the name of the coal mine (and coal seam), coal storage facility, or coal preparation plant (where the sample was collected);

(iii) The results of the analysis of the coal from which the shipment came (or of the shipment itself) including the sulfur content, moisture content, ash content, and heat content; and

(iv) The methods used to determine the properties of the coal.

(4) For other fuels:

(i) The name of the supplier of the fuel;

(ii) The potential sulfur emissions rate or maximum potential sulfur emissions rate of the fuel in ng/J heat input; and

(iii) The method used to determine the potential sulfur emissions rate of the fuel.

(g)

(1) Except as provided under paragraphs (g)(2) and (g)(3) of this section, the owner or operator of each affected facility shall record and maintain records of the amount of each fuel combusted during each operating day.

(2) As an alternative to meeting the requirements of paragraph (g)(1) of this section, the owner or operator of an affected facility that combusts only natural gas, wood, fuels using fuel certification in §60.48c(f) to demonstrate compliance with the SO_2standard, fuels not subject to an emissions standard (excluding opacity), or a mixture of these fuels may elect to record and maintain records of the amount of each fuel combusted during each calendar month.

(3) As an alternative to meeting the requirements of paragraph (g)(1) of this section, the owner or operator of an affected facility or multiple affected facilities located on a contiguous property unit where the only fuels combusted in any steam generating unit (including steam generating units not subject to this subpart) at that property are natural gas, wood, distillate oil meeting the most current requirements in §60.42C to use fuel certification to demonstrate compliance with the SO_2standard, and/or fuels, excluding coal and residual oil, not subject to an emissions standard (excluding opacity) may elect to record and maintain records of the total amount of each steam generating unit fuel delivered to that property during each calendar month.

(h) The owner or operator of each affected facility subject to a federally enforceable requirement limiting the annual capacity factor for any fuel or mixture of fuels under §60.42c or §60.43c shall calculate the annual capacity factor individually for each fuel combusted. The annual capacity factor is determined on a 12-month rolling average basis with a new annual capacity factor calculated at the end of the calendar month.

(i) All records required under this section shall be maintained by the owner or operator of the affected facility for a period of two years following the date of such record.

(j) The reporting period for the reports required under this subpart is each six-month period. All reports shall be submitted to the Administrator and shall be postmarked by the 30th day following the end of the reporting period.

[72 FR 32759, June 13, 2007, as amended at 74 FR 5091, Jan. 28, 2009]

Indiana Department of Environmental Management
Office of Air Quality

Technical Support Document (TSD) for a Re-Registration

Source Description and Location

Source Name: **Electric Coatings Technologies, LLC**
Source Location: **4407 Railroad Avenue, East Chicago, Indiana 46312**
County: **Lake**
SIC Code: **3313**
Registration No.: **089-28195-00343**
Permit Reviewer: **Sandra Carr**

On July 2, 2009, the Office of Air Quality (OAQ) received an application from Electric Coatings Technologies, LLC related to the operation of an existing continuous coil electrogalvanizing plant

Existing Approvals

The source has been operating under previous approvals including, but not limited to, the following:

(a) Notice Only Change No. 089-19266-00373, issued on June 16, 2004.

(b) Notice Only Change No. 089-17959-00373, issued on August 4, 2003.

(c) Notice Only Change No. 089-15893-00373, issued on May 1, 2002.

(d) Re-Registration No. 089-13740-00373, issued on October 12, 2001.

(e) Notice Only Change No. 089-00000-00373, issued on July 23, 1999.

(f) Registration No. 089-6854-00373, issued on December 17, 1996.

County Attainment Status

The source is located in Lake County.

Pollutant	Designation
SO_2	Better than national standards.
CO	Attainment effective February 18, 2000, for the part of the city of East Chicago bounded by Columbus Drive on the north; the Indiana Harbor Canal on the west; 148th Street, if extended, on the south; and Euclid Avenue on the east. Unclassifiable or attainment effective November 15, 1990, for the remainder of East Chicago and Lake County.
O_3	Nonattainment Subpart 2 Moderate effective June 15, 2004, for the 8-hour ozone standard.[1]
PM_{10}	Attainment effective March 11, 2003, for the cities of East Chicago, Hammond, Whiting, and Gary. Unclassifiable effective November 15, 1990, for the remainder of Lake County.
NO_2	Cannot be classified or better than national standards.
Pb	Not designated.
[1]Nonattainment Severe 17 effective November 15, 1990, for the Chicago-Gary-Lake County area for the 1-hour ozone standard which was revoked effective June 15, 2005. Basic nonattainment designation effective federally April 5, 2005, for $PM_{2.5}$.	

(Air Pollution Control Board; 326 IAC 1-4-46; filed Dec 26, 2007, 1:43 p.m.: 20080123-IR-326070308FRA)

(a) Ozone Standards

Volatile organic compounds (VOC) and Nitrogen Oxides (NOx) are regulated under the Clean Air Act (CAA) for the purposes of attaining and maintaining the National Ambient Air Quality Standards (NAAQS) for ozone.

(i) 1-hour ozone standard

On December 22, 2006 the United States Court of Appeals, District of Columbia issued a decision which served to partially vacate and remand the U.S. EPA's final rule for implementation of the eight-hour National Ambient Air quality Standard for ozone. *South Coast Air Quality Mgmt. Dist. v. EPA*, 472 F.3d 882 (D.C. Cir., December 22, 2006), *rehearing denied* 2007 U.S. App. LEXIS 13748 (D.C. Cir., June 8, 2007). The U.S. EPA has instructed IDEM to issue permits in accordance with its interpretation of the *South Coast* decision as follows: Gary-Lake-Porter County was previously designated as a severe non-attainment area prior to revocation of the one-hour ozone standard, therefore, pursuant to the anti-backsliding provisions of the Clean Air Act, any new or existing source must be subject to the major source applicability cut-offs and offset ratios under the area's previous one-hour standard designation. This means that a source must achieve the Lowest Achievable Emission Rate (LAER) if it exceeds 25 tons per year of VOC emissions and must offset any increase in VOC emissions by a decrease of 1.3 times that amount.

On January 26, 1996 in 40 CFR 52.777(i), the U.S. EPA granted a waiver of the requirements of Section 182(f) of the CAA for Lake and Porter Counties, including the lower NOx threshold for nonattainment new source review. Therefore, VOC emissions alone are considered when evaluating the rule applicability relating to the 1-hour ozone standards. Therefore, VOC emissions were reviewed pursuant to the requirements for Emission Offset, 326 IAC 2-3. See the State Rule Applicability for the source section.

(ii) 8-hour ozone standard

VOC and NOx emissions are considered when evaluating the rule applicability relating to the 8-hour ozone standard. Lake County has been designated as nonattainment for the 8-hour ozone standard. Therefore, VOC and NOx emissions were reviewed pursuant to the requirements for Emission Offset, 326 IAC 2-3. See the State Rule Applicability – Entire Source section.

(b) $PM_{2.5}$

U.S. EPA, in the Federal Register Notice 70 FR 943 dated January 5, 2005, has designated Lake County as nonattainment for $PM_{2.5}$. On March 7, 2005 the Indiana Attorney General's Office, on behalf of IDEM, filed a law suit with the Court of Appeals for the District of Columbia Circuit challenging U.S. EPA's designation of nonattainment areas without sufficient data. However, in order to ensure that sources are not potentially liable for a violation of the Clean Air Act, the OAQ is following the U.S. EPA's New Source Review Rule for $PM_{2.5}$ promulgated on May 8th, 2008, and effective on July 15th 2008. Therefore, direct $PM_{2.5}$ and SO_2 emissions were reviewed pursuant to the requirements of Nonattainment New Source Review, 326 IAC 2-1.1-5. See the State Rule Applicability – Entire Source section.

(c) Other Criteria Pollutants

Lake County has been classified as attainment or unclassifiable in Indiana for PM_{10}, SO_2, NO_X, VOC, and CO. Therefore, these emissions were reviewed pursuant to the requirements for Prevention of Significant Deterioration (PSD), 326 IAC 2-2.

Fugitive Emissions

The fugitive emissions of criteria pollutants and hazardous air pollutants are counted toward the determination of 326 IAC 2-5.5 (Registrations) applicability.

Background and Description of Emission Units and Pollution Control Equipment

The Office of Air Quality (OAQ) has reviewed an application, submitted by Electric Coatings Technologies, LLC on July 2, 2009, requesting that IDEM OAQ review the updated plant operations and potential to emit (PTE) emissions calculations. Pursuant to the review, IDEM has decided to issue a Re-Registration of Electric Coatings Technologies, LLC.

The source consists of the following existing emission units:

(a) Two (2) natural gas-fired boilers, identified as Boiler #2 and Boiler #3, constructed after June 9, 1989, each equipped with low NO_X burners, each with a capacity of 21.0 million British thermal units per hour, with no control, exhausting to stacks SS-2 & SS-3, respectively.

Under New Source Performance Standards for Small Industrial-Commercial-Institutional Steam Generating Units, 60.40c, Subpart Dc, the boilers, identified as Boiler #2 and Boiler #3, are considered affected sources.

(b) One (1) electrogalvanizing line, coating coiled metal strips, consisting of multiple stations including: pre-cleaning, degreasing, zinc galvanizing, phosphate & chromium baths, and electrostatic oiling. This line has a maximum operating capacity of 350 feet of metal coil per minute, with a wet scrubber, identified as the plating fume scrubber, for particulate control, exhausting to stacks SS-1, SS-4, SS-5, and SS-6.

(c) Two (2) natural gas fired space heaters, identified as #1 West and #2 East, each with a capacity of 8.80 million British thermal units per hour, with no control, exhausting inside the building.

Enforcement Issues

There are no pending enforcement actions related to this source.

Emission Calculations

See Appendix A of this TSD for detailed emission calculations.

Permit Level Determination – Registration

The following table reflects the unlimited potential to emit (PTE) of the entire source before controls. Control equipment is not considered federally enforceable until it has been required in a federally enforceable permit.

Process/Emission Unit	Potential To Emit of the Entire Source (tons/year)								
	PM	PM_{10}*	$PM_{2.5}$	SO_2	NO_X	VOC	CO	Total HAP	Worst Individual HAP
Boilers (# 2 & # 3)	0.34	1.37	1.37	0.11	9.02	0.99	15.15	0.34	0.32 Hexane
Electrogalvanizing	negl.	negl.	negl.	negl.	negl.	12.86	negl.	negl.	negl.
Space Heaters	0.14	0.57	0.57	0.05	7.56	0.42	6.35	0.14	0.14 Hexane
Total PTE of Entire Source	**0.49**	**1.95**	**1.95**	**0.15**	**16.58**	**14.27**	**21.50**	**0.48**	
Registration Levels	25	25	25	25	25	25	100	25	10

negl. = negligible
* Under the Part 70 Permit program (40 CFR 70), particulate matter with an aerodynamic diameter less than or equal to a nominal 10 micrometers (PM10), not particulate matter (PM), is considered as a "regulated air pollutant".

Criteria Pollutants

(a) The potential to emit (PTE) (as defined in 326 IAC 2-1.1-1(16)) of NO_X and VOC are still within the ranges listed in 326 IAC 2-5.1-2(a)(1). The PTE of all other regulated criteria pollutants are less than the ranges listed in 326 IAC 2-5.1-2(a)(1). Therefore, the source is still subject to the provisions of 326 IAC 2-5.1-2 (Registrations). A Re-Registration will be issued.

Hazardous Air Pollutants

(b) The potential to emit (PTE) (as defined in 326 IAC 2-1.1-1(16)) of any single HAP is less than ten (10) tons per year and the PTE of a combination of HAP is less than twenty-five (25) tons per year. Therefore, this source is an area source under Section 112 of the Clean Air Act (CAA) and not subject to the provisions of 326 IAC 2-7.

Federal Rule Applicability Determination

New Source Performance Standards (NSPS)

(a) The two (2) natural gas-fired boilers, identified as Boiler-2 and Boiler-3, are subject to the New Source Performance Standards for Small Industrial-Commercial-Institutional Steam Generating Units (40 CFR 60, Subpart Dc), because the boilers are steam generating units, were constructed after June 9, 1989, and each has a maximum heat input capacity which is greater than 10 million British thermal units per hour and less than 100 million British thermal units per hour (MMBtu/hr).

Pursuant to 60.40c(a), an affected facility is each steam generating unit that meets the applicability requirements in the above paragraph

The affected facilities at this source which are subject to this rule include the following:

Two (2) natural gas-fired boilers, identified as Boiler-2 and Boiler-3.

Applicable portions of the NSPS are the following:

(1) 40 CFR 60.40c(a)
(2) 40 CFR 60.40c(b)
(3) 40 CFR 60.40c(c)
(4) 40 CFR 60.40c(d)
(5) 40 CFR 60.41c

(6) 40 CFR 60.48c(a)(1)
(7) 40 CFR 60.48c(a)(3)
(8) 40 CFR 60.48c(g)(2)
(9) 40 CFR 60.48c(g)(3)
(10) 40 CFR 60.48c(i)
(11) 40 CFR 60.48c(j)

Nonapplicable portions of the NSPS will not be included in the permit.

Operating on fuels other than natural gas may cause the requirements of 40 CFR 60.42c, 40 CFR 60.43c, 40 CFR 60.44c, 40 CFR 60.45c, 40 CFR 60.46c and 40 CFR 60.47c to be applicable to the two (2) boilers, identified as Boiler-2 and Boiler-3, and shall require prior IDEM, OAQ, approval.

The requirements of 40 CFR Part 60, Subpart A – General Provisions, which are incorporated as 326 IAC 12-1, apply to the two (2) natural gas-fired boilers, identified as Boiler-2 and Boiler-3, except as otherwise specified in 40 CFR 60, Subpart Dc.

(b) The coating applied by the electrostatic oiler is not subject to requirements of the New Source Performance Standards (NSPS) for Metal Coil Surface Coating, 40 CFR 60.460, Subpart TT, (326 IAC 12), because the coating, although organic in nature, is a protective oil.

According to the manufacturer, the electrostatic oiler applies a coating of electrically resistive oil, such as oil to a steel strip, for the purpose of corrosion resistance, or drawing lubrication. The oiler is "designed to utilize only electrostatic forces to propel the coating to the strip, no air or fluid pressures that cause overspray, are used in the system". The protective oil is applied after the galvanized coating to protect the steel from rust during transportation and storage.

The definition of *protective oil* as stated in CFR 63.5110 *“means an organic material that is applied to metal for the purpose of providing lubrication or protection from corrosion without forming a solid film. This definition of protective oil includes but is not limited to lubricating oils, evaporative oils (including those that evaporate completely), and extrusion oils.”*

The definition of *coating* as stated in CFR 63.5110 is “*material applied onto or impregnated into a substrate for decorative, protective, or functional purposes. Such materials include, but are not limited to, paints, varnishes, sealants, inks, adhesives, maskants, and temporary coatings. Decorative, protective, or functional materials that consist only of solvents, protective oils, acids, bases, or any combination of these substances are not considered coatings”.*

Therefore, the protective oil applied by the electrostatic oiler is not subject to the requirements of subpart TT. Additionally, the other coatings applied in the electrogalvanizing line are also not subject to the requirements of Subpart TT because those coatings are not organic.

(c) There are no other New Source Performance Standards (NSPS) (326 IAC 12 and 40 CFR Part 60) included in the permit.

<u>National Emission Standards for Hazardous Air Pollutants (NESHAP)</u>

(d) The requirements of the National Emission Standards for Hazardous Air Pollutants (NESHAP) for Chromium Emissions From Hard and Decorative Chromium Electroplating and Chromium Anodizing Tanks, 40 CFR 63.340, Subpart N, (326 IAC 20-8), are not included in this permit, because, although this source does roll coat an aqueous chromium solution onto a coiled metal substrate, it does not perform any hard chromium electroplating, decorative chromium electroplating, or chromium anodizing.

(e) The requirements of the National Emission Standards for Hazardous Air Pollutants (NESHAP) for Surface Coating Of Metal Cans, 40 CFR 63.3480, Subpart KKKK (326 IAC 20-86), are not included in the permit because this source is not a major source of HAP and does not produce cans.

(f) The requirements of the National Emission Standards for Hazardous Air Pollutants (NESHAP) for Surface Coating of Miscellaneous Metal Parts and Products, 40 CFR 63.3880, Subpart MMMM (326 IAC 20-80), are not included in the permit because this source is not a major source of HAP.

(g) The requirements of the National Emission Standards for Hazardous Air Pollutants (NESHAP) for Surface Coating of Metal Furniture, 40 CFR 63.4880, Subpart RRRR (326 IAC 20-78), are not included in the permit because this source is not a major source of HAP and does not produce metal furniture.

(h) The requirements of the National Emission Standards for Hazardous Air Pollutants (NESHAP) for Surface Coating Of Metal Coil, 40 CFR 63.5080, Subpart SSSS (326 IAC 20-64), are not included in the permit because this source is not a major source of HAP.

(i) The requirements of the National Emission Standards for Hazardous Air Pollutants (NESHAP) for Industrial, Commercial, and Institutional Boilers and Process Heaters, 40 CFR 63.7480, Subpart DDDDD (326 IAC 20-95), are not included in the permit because this source is not a major source of HAP.

(j) The requirements of the National Emission Standards for Hazardous Air Pollutants (NESHAP) for Paint Stripping and Miscellaneous Surface Coating Operations at Area Sources, 40 CFR 63.11169, Subpart HHHHHH (326 IAC 20-1), are not included in the permit, because, although this source does roll coat an aqueous chromium solution onto a coiled metal substrate, it does not perform spray application of coatings that contain the target HAP, as defined in §63.11180. Pursuant to the definitions included in HHHHHH, spray-applied coatings do not include the following materials or activities: "non-atomizing application technology, including, but not limited to, paint brushes, rollers, hand wiping, flow coating, dip coating, electrodeposition coating, web coating, coil coating, touch-up markers, or marking pens."

(k) There are no National Emission Standards for Hazardous Air Pollutants (NESHAPs) (326 IAC 14, 326 IAC 20 and 40 CFR Part 63) included in the permit.

Compliance Assurance Monitoring (CAM)

(l) Pursuant to 40 CFR 64.2, Compliance Assurance Monitoring (CAM) is not included in the permit, because the unlimited potential to emit of the source is less than the Title V major source thresholds and the source is not required to obtain a Part 70 or Part 71 permit.

State Rule Applicability Determination

The following state rules are applicable to the source:

(a) 326 IAC 2-5.5 (Registrations)
Registration applicability is discussed under the Permit Level Determination – Registration section above.

(b) 326 IAC 2-4.1 (Major Sources of Hazardous Air Pollutants (HAP))
The potential to emit of any single HAP is less than ten (10) tons per year and the potential to emit of a combination of HAP is less than twenty-five (25) tons per year. Therefore, this source is an area source under Section 112 of the Clean Air Act (CAA) and not subject to the provisions of 326 IAC 2-4.1.

(c) 326 IAC 2-6 (Emission Reporting)
Pursuant to 326 IAC 2-6-1, this source is not subject to this rule, because it is not required to have an operating permit under 326 IAC 2-7 (Part 70), it is located in Lake County, it has actual emissions of NOx and VOC of less than twenty-five (25) tons per year, and it does not emit lead into the ambient air at levels equal to or greater than 5 tons per year. Therefore, 326 IAC 2-6 does not apply.

(d) 326 IAC 2-5.1-3 (Permits)
Pursuant to 326 IAC 2-5-1-3(a)(2)(A), this source is not subject to this rule, because, although this source does roll coat an aqueous chromium solution onto a coiled metal substrate, it does not perform chromium electroplating or chromium anodizing. Therefore, 326 IAC 2-5.1-3 does not apply.

(e) 326 IAC 2-6.1-3 (Minor Source Operating Permit Program)
Pursuant to 326 IAC 2-6-1-3(a), this source is not subject to this rule, because, although this source does roll coat an aqueous chromium solution onto a coiled metal substrate, it does not perform chromium electroplating or chromium anodizing. Therefore, 326 IAC 2-6.1-3 does not apply.

(f) 326 IAC 5-1 (Opacity Limitations)
Pursuant to 326 IAC 5-1-2 (Opacity Limitations), except as provided in 326 IAC 5-1-3 (Temporary Alternative Opacity Limitations), opacity shall meet the following, unless otherwise stated in this permit:

(1) Opacity shall not exceed an average of twenty percent (20%) in any one (1) six (6) minute averaging period as determined in 326 IAC 5-1-4.

(2) Opacity shall not exceed sixty percent (60%) for more than a cumulative total of fifteen (15) minutes (sixty (60) readings as measured according to 40 CFR 60, Appendix A, Method 9 or fifteen (15) one (1) minute nonoverlapping integrated averages for a continuous opacity monitor) in a six (6) hour period.

(g) 326 IAC 6-4 (Fugitive Dust Emissions Limitations)
Pursuant to 326 IAC 6-4 (Fugitive Dust Emissions Limitations), the source shall not allow fugitive dust to escape beyond the property line or boundaries of the property, right-of-way, or easement on which the source is located, in a manner that would violate 326 IAC 6-4.

(h) 326 IAC 6.8 (Particulate Matter Limitations for Lake County)
Pursuant to 326 IAC 6.8-1-1(a)(2), this rule applies to Lake County sources which have a potential to emit PM equal to or greater than 100 tons per year or actual PM emissions equal to or greater than 10 tons per year. Since this source has potential and actual PM emissions of less than 10 tons per year, the requirements of 326 IAC 6.8 do not apply. This source will be subject to the requirements of 326 IAC 6-3-2 and to 326 IAC 6-2-4.

(i) 326 IAC 7-1.1 (Sulfur Dioxide Emission Limitations)
This rule applies to sources which have SO_2 emissions of greater than 25 tons per year. This source combusts only natural gas and has potential SO_2 emissions of less than 25 tons per year, therefore, the requirements of 326 IAC 7-1.1 are not applicable.

(j) 326 IAC 8-1-6 (VOC Rules: General Reduction Requirements for New Facilities)
Since the unlimited potential emissions from each emission unit is less than twenty-five (25) tons VOC per year, the emission units at this source is not subject to the requirements of 326 IAC 8-1-6.

<u>Electrogalvanizing Line</u>

(k) 326 IAC 6-3-2 (Particulate Emission Limitations for Manufacturing Processes)
Pursuant to 326 IAC 6-3-1.5(5), “surface coating does not include galvanizing", therefore the electrogalvanizing line is not subject to the requirements of 326 IAC 6-3-2(d) and emissions from this process shall be regulated under 326 IAC 6-3-2(e).

Pursuant to 326 IAC 6-3-2, the particulate matter (PM) from the electrogalvanizing line shall not exceed 55.2 pounds per hour when operating at a process weight rate of 292,000 pounds (146 tons) per hour.

Interpolation and extrapolation of the data for the process weight rate in excess of sixty thousand (60,000) pounds per hour shall be accomplished by use of the equation:

$E = 55.0\ P^{0.11} - 40$

where

E = rate of emission in pounds per hour; and
P = process weight rate in tons per hour

(l) 326 IAC 8-2-4 (Coil Coating Operations)
This rule, 326 IAC 8-2-4 (Coil Coating Operations), establishes VOC emission limitations for the coating of any flat metal sheet or strips that come in rolls or coils. The electrogalvanizing line is made up of five stations with different processes performed at each station. While the other four stations have no VOC emissions and are not subject to this rule, the electrostatic oiler portion of the line is subject to 326 IAC 8-2-4.

The Permittee shall limit the daily volume weighted average volatile organic compound (VOC) content of coating delivered to the applicators at the electrostatic oiler to 2.6 pounds of VOC per gallon of coating less water.

The Permittee shall comply with the emission limitations in 326 IAC 8 as follows:

(a) Pursuant to 326 IAC 8-1-2(a)(7), the source shall comply using either compliant coatings or, if non-compliant coatings are used, a daily volume-weighted average.

(1) The surface coating operations performed with the electrostatic oiler shall use compliant coatings.

(2) The source shall record the manufacurer's product number and the amount of each coating used each day.

(3) If non-compliant coatings are used, the daily volume-weighted VOC content shall be calculated using the following equation:

$$A = \left(\sum C \times U\right) / \left(\sum U\right)$$

where:

A = Volume weighted average (pounds VOC/gallon, less water as applied);

C = VOC content of the coating (pounds VOC/gallon, less water as applied); and

U = Usage rate of the coating (gallons/day).

(m) 326 IAC 8-2-9 (Miscellaneous Metal Coating)
Although this source does operate under the SIC code of 3313, which is specified in 326 IAC 8-2-9(a)(5), this source is subject to the requirements of 326 IAC 8-2-4 (Coil Coating Operations) and is therefore not subject to 326 IAC 8-2-9.

(n) 326 IAC 8-3 (Organic Solvent Degreasing Operations)
The provisions of 326 IAC 8-3 regulate facilities in Lake County that perform *organic solvent degreasing operations* (Section 3.1.1) and have potential VOC emissions of 100 tons or greater. Although this source does have a station in the electrogalvanizing line which is labeled "degreasing", the degreasing at this source is done using inorganic caustic solutions (NaOH). Since no organic solvents are used for degreasing, this source is not subject to the requirements of 326 IAC 8-3.

Boilers

(o) 326 IAC 6-2-4 (Particulate Emission Limitations for Sources of Indirect Heating)
Pursuant to 326 IAC 6-2-1(d), facilities constructed after September 21, 1983 are subject to 326 IAC 6-2-4. The two (2) boilers, identified as Boiler-2 & Boiler-3, received permits to construct after September 21, 1983, therefore, the two (2) boilers are subject to the requirements of 326 IAC 6-2-4.

There are no PM emission limitations in 40 CFR 60, Subpart Dc applicable to natural gas-fired boilers. Therefore, the boilers, identified as Boiler-2 & Boiler-3, will not be subject to a more stringent limit under 326 IAC 12.

The PM from each of the two (2) boilers shall be limited to 0.41 pounds per million British thermal unit of heat input. The emission limitations are based on the following equation given in 326 IAC 6-2-4:

$$P_t = 1.09/Q^{0.26}$$

where:

P_t = Pounds of particulate matter emitted per million British thermal units (lb/MMBtu) heat input

Q = Total source maximum operating capacity rating in million British thermal units per hour (MMBtu/hr) heat input. The maximum operating capacity rating is defined as the maximum capacity at which the facility is operated or the nameplate capacity, whichever is specified in the facility's permit application, except when some lower capacity is contained in the facility's operation permit; in which case, the capacity specified in the operation permit shall be used.

The heat input capacities of the two (2) boilers are 21.0 million British thermal units per hour, each.

$Pt = 1.09/(42.0)^{0.26} = 0.412$ lb/MMBtu heat input

Based on Appendix A, the total potential PM emission rate is:

0.350 ton/yr × (2000 lbs/ton / 8760 hrs/yr) = 0.080 lb/hr
(0.080 lb/hr / 42.0 MMBtu/hr) = 0.002 lb PM per MMBtu

Therefore, the two (2) boilers, identified as Boiler-2 & Boiler-3, will be able to comply with this rule without the use of a control.

(p) 326 IAC 12 (New Source Performance Standards)
See Federal Rule Applicability Section of this TSD.

Conclusion and Recommendation

Unless otherwise stated, information used in this review was derived from the application and additional information submitted by the applicant. An application for the purposes of this review was received on July 2, 2009.

The operation of this source shall be subject to the conditions of the attached proposed Registration No. 089-28195-00373. The staff recommends to the Commissioner that this Registration be approved.

IDEM Contact

(a) Questions regarding this proposed permit can be directed to Sandra Carr at the Indiana Department Environmental Management, Office of Air Quality, Permits Branch, 100 North Senate Avenue, MC 61-53 IGCN 1003, Indianapolis, Indiana 46204-2251 or by telephone at (317) 234-5372 or toll free at 1-800-451-6027 extension 45372.

(b) A copy of the findings is available on the Internet at: http://www.in.gov/ai/appfiles/idem-caats/

(c) For additional information about air permits and how the public and interested parties can participate, refer to the IDEM's Guide for Citizen Participation and Permit Guide on the Internet at: www.idem.in.gov

Appendix A: Emissions Calculations
Natural Gas Combustion
MM BTU/HR <100
Two (2) Direct Fired Gas Space Heaters

Company Name: **Electric Coating Technologies, LLC**
Address City IN Zip: **4407 Railroad Avenue, East Chicago, Indiana 46312**
Registration: **089-28195-00373**
Reviewer: **Sandra Carr**
Application Date: **July 2, 2009**

Heat Input Capacity MMBtu/hr	Potential Throughput MMCF/yr
17.6	151.15

Pollutant

	PM*	PM_{10}*	$PM_{2.5}$*	SO_2	NOx	VOC	CO
Emission Factor in lb/MMCF	1.9	7.6	7.6	0.6	100.0 **see below	5.5	84.0
Potential Emission in tons/yr	0.144	0.574	0.574	0.045	7.56	0.416	6.35

*PM emission factor is filterable PM only. PM_{10} emission factor is filterable and condensable PM_{10} combined. The US EPA has directed PM_{10} act as surrogate for $PM_{2.5}$.

**Emission Factors for NOx: Uncontrolled = 100, Low NOx Burner = 50, Low NOx Burners/Flue gas recirculation = 32

Methodology

All emission factors are based on normal firing.

MMBtu = 1,000,000 Btu

MMCF = 1,000,000 Cubic Feet of Gas

Potential Throughput (MMCF) = Heat Input Capacity (MMBtu/hr) x 8,760 hrs/yr x 1 MMCF/1,020 MMBtu

Emission Factors are from AP 42, Chapter 1.4, Tables 1.4-1, 1.4-2, 1.4-3, SCC #1-02-006-02, 1-01-006-02, 1-03-006-02, and 1-03-006-03 (SUPPLEMENT D 3/98)

Emission (tons/yr) = Throughput (MMCF/yr) x Emission Factor (lb/MMCF)/2,000 lb/ton

See page 2 for HAP emissions calculations.

Appendix A: Emissions Calculations
Natural Gas Combustion
MM BTU/HR <100
Two (2) Direct Fired Gas Space Heaters

Company Name: Electric Coating Technologies, LLC
Address City IN Zip: 4407 Railroad Avenue, East Chicago, Indiana 46312
Registration: 089-28195-00373
Reviewer: Sandra Carr
Application Date: July 2, 2009

HAP - Organics

	Benzene	Dichlorobenzene	Formaldehyde	Hexane	Toluene
Emission Factor in lb/MMcf	2.1E-03	1.2E-03	7.5E-02	1.8E+00	3.4E-03
Potential Emission in tons/yr	1.59E-04	9.07E-05	5.67E-03	1.36E-01	2.57E-04

HAP - Metals

	Lead	Cadmium	Chromium	Manganese	Nickel	**Total HAP**
Emission Factor in lb/MMcf	5.0E-04	1.1E-03	1.4E-03	3.8E-04	2.1E-03	
Potential Emission in tons/yr	3.78E-05	8.31E-05	1.06E-04	2.87E-05	1.59E-04	**0.143**

Highest Individual HAP = 0.14 Hexane

Methodology is the same as page 1.
The five highest organic and metal HAP emission factors are provided above.
Additional HAP emission factors are available in AP-42, Chapter 1.4.

Able to comply with 326 IAC 6-2-3?

Appendix A: Emissions Calculations
Natural Gas Combustion
MMBtu/hr <100
Two (2) Natural Gas Boilers with Low NOx Burners

Company Name: **Electric Coatings Technologies, LLC**
Address City IN Zip: **4407 Railroad Avenue, East Chicago, Indiana 46312**
Registration: **089-28195-00373**
Reviewer: **Sandra Carr**
Application Date: **July 2, 2009**

Heat Input Capacity MMBtu/hr	Potential Throughput MMCF/yr
42.0	360.71

Pollutant

	PM*	PM_{10}*	$PM_{2.5}$*	SO_2	NO_X	VOC	CO
Emission Factor in lb/MMCF	1.9	7.6	7.6	0.6	50.0 **see below	5.5	84.0
Potential Emission in tons/yr	0.343	1.37	1.37	0.108	9.02	0.99	15.1

*PM emission factor is filterable PM only. PM_{10} emission factor is filterable and condensable PM_{10} combined. As directed by the US EPA, PM_{10} is to act as a surrogate for $PM_{2.5}$.

**Emission Factors for NOx: Uncontrolled = 100, Low NOx Burner = 50, Low NOx Burners/Flue gas recirculation = 32

Methodology

All emission factors are based on normal firing.

MMBtu = 1,000,000 Btu

MMCF = 1,000,000 Cubic Feet of Gas

Potential Throughput (MMCF) = Heat Input Capacity (MMBtu/hr) x 8,760 hrs/yr x 1 MMCF/1,020 MMBtu

Emission Factors are from AP 42, Chapter 1.4, Tables 1.4-1, 1.4-2, 1.4-3, SCC #1-02-006-02, 1-01-006-02, 1-03-006-02, and 1-03-006-03 (SUPPLEMENT D 3/98)

Emission (tons/yr) = Throughput (MMCF/yr) x Emission Factor (lb/MMCF)/2,000 lb/ton

Appendix A: Emissions Calculations
Natural Gas Combustion
MMBtu/hr <100
Two (2) Natural Gas Boilers with Low NOx Burners

Company Name: Electric Coatings Technologies, LLC
Address City IN Zip: 4407 Railroad Avenue, East Chicago, Indiana 46312
Registration: 089-28195-00373
Reviewer: Sandra Carr
Application Date: July 2, 2009

HAP - Organics

	Benzene	Dichlorobenzene	Formaldehyde	Hexane	Toluene
Emission Factor in lb/MMcf	2.1E-03	1.2E-03	7.5E-02	1.8E+00	3.4E-03
Potential Emission in tons/yr	3.79E-04	2.16E-04	1.35E-02	3.25E-01	6.13E-04

HAP - Metals

	Lead	Cadmium	Chromium	Manganese	Nickel	**Total HAP**
Emission Factor in lb/MMcf	5.0E-04	1.1E-03	1.4E-03	3.8E-04	2.1E-03	
Potential Emission in tons/yr	9.02E-05	1.98E-04	2.52E-04	6.85E-05	3.79E-04	**0.340**

Methodology is the same as page 3.

Highest Individual HAP = 0.32 Hexane

The five highest organic and metal HAP emission factors are provided above.
Additional HAP emission factors are available in AP-42, Chapter 1.4.

Appendix A: Emissions Calculations
Electrogalvanizing

Company Name: **Electric Coatings Technologies, LLC**
Address City IN Zip: **4407 Railroad Avenue, East Chicago, Indiana 46312**
Registration: **089-28195-00373**
Reviewer: **Sandra Carr**
Application Date: **July 2, 2009**

CLEANING SECTION:

The cleaning section provides pre-cleaning of the steel strip prior to electrolytic cleaning.
Cleaner tanks 1 and 2 maintain a NaOH and/or KOH solution in the range of 2% to 4%.
This section does not contain emissions of any regulated pollutants.
The dedicated exhaust fan system's purpose is to evacuate heat and humidity from the building (SS-5).
Emissions of the humid air would contain negligible amounts of particulate matter, if any.
Therefore, emission calculations are not considered for the cleaning section.

DEGREASING SECTION (Electrolytic Cleaning):

The degreasing section provides electrolytic cleaning of the steel strip.
The cleaning tank maintains a NaOH and/or KOH solution in the range of 5% to 9%.
This section does not contain emissions of any regulated pollutants.
The dedicated exhaust fan system's purpose is to evacuate heat and humidity from the building (SS-4).
Emissions of the humid air would contain negligible amounts of particulate matter, if any.
For the same reasons explained above, emission calculations are not considered for the degreasing section.

ZINC ELETROPLATING SECTION:

The zinc electroplating section is operated two steps, surface activation/rinsing & plating/rinsing.
The surface activation bath prepares the surface prior to plating with a sulfuric acid concentration of 5% to 8%.
The zinc electroplating bath (5 cells) operates with a sulfuric acid concentration of 10% to 15%.
The exhaust and control system consists of a mist eliminator & packed bed scrubber (SS-1).

Given,

140	g/L, max zinc bath conc (ranges 100-140 g/L)
28.35	grams per ounce
3.785	liters per gallon
50000	acfm, max fan speed
100	degrees F, stack gas temp
38	degrees C, stack gas temp
47321	scfm, max fan speed

Uncontrolled emissions for nonchromium electroplating:
Per AP-42, Section 12.20 Equation 1, July 1996,
The emission factor (EFz) for uncontrolled emissions of zinc (z), gr/dscf, is calculated as follows,

Equation 1 $EFz = (3.3 \times 10^{-7}) \times (EEz/ez) \times Cz \times Dz$

EEz = A-hr/mil-ft^2, electrochemical equivalent for zinc
ez = %, cathode efficiency for zinc
Cz = oz/gal, bath concentration for zinc
Dz = A/ft^2, current density for zinc

If,

EEz =	0.91269841	A-hr/mil-ft^2	(230,000 A-hr/252,000 ft^2 per facility data sources, assuming 1 mil coating)
ez =	50%		(per EPA Background sample calculations for electroplating zinc, conservative)
Cz =	18.69	oz/gal	
Dz =	383.0	A/ft^2	(per facility data sources)

Then,

0.00431	gr/dscfm	Emission Rate for Zinc
0.0000146	**tpy uncontrolled zinc emissions**	

Appendix A: Emissions Calculations
Electrogalvanizing

Company Name: Electric Coatings Technologies, LLC
Address City IN Zip: 4407 Railroad Avenue, East Chicago, Indiana 46312
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Reviewer: Sandra Carr
Application Date: July 2, 2009

Since the faciltiy recycles their plating solution, testing has been done for lead concentrations which cycle up in the system.

4	mg/L, known max lead concentration
0.004	g/L, max lead bath conc

Using the same calculation method for zinc above,

EEI =	0.91269841	A-hr/mil-ft^2
el =	50%	
Cl =	29.96	oz/gal
Dl =	383.0	A/ft^2

Then,

0.00691	gr/dscfm	Emission Rate for Lead
0.0000234	**tpy uncontrolled lead emissions**	

Since metallic emissions are insignificant, we can assume particulate matter emissions are also insignificant.
However, we can estimate particulate emissions in accordance with Section 12.20 Background Document.
Section 4.2.5 uses an acid to metal ratio to estimate the particulate emissions.

Chemical formula for sulfuric acid:	H_2SO4
Molecular wt of zinc oxide in sulfuric acid:	81.39
Molecular wt of sulfuric acid:	98.07
Molecular wt ratio of acid to metal:	1.2

Therefore, the emission factor for PM for zinc electroplating is estimated as:

EFpm = 1.2 x EFz

Then,

0.00520	gr/dscf	Emission Rate for PM
0.0000176	**tpy uncontrolled $PM_{2.5}$/PM_{10}/PM emissions**	

CHEMICAL TREATMENT SECTION:

The chemical treatment section provides passivation treatment for the metal surface prior to oiling.
A phosphate-based treatment is used as well as a chromium-based treatment.
The phosphate-based treatment is applied through a bath system (1-2 lbs/gal concentration).
The chromium-based treatment is applied through a roll coater system (12-20% concentration).
Neither of the systems contains any VOC containing chemicals.
The phosphate-based treatment section does not contain emissions of any regulated pollutants.
The chromium-based treatment section does not emit or aerosolized anything based on the roll-coater application.
The dedicated exhaust fan system's purpose is to evacuate heat and humidity from the phosphate section (SS-6).
Emissions of the humid air would contain negligible amounts of particulate matter, if any.
Therefore, emission calculations are not considered for the chemical treatment section.

Appendix A: Emissions Calculations
Electrogalvanizing

Company Name: Electric Coatings Technologies, LLC
Address City IN Zip: 4407 Railroad Avenue, East Chicago, Indiana 46312
Registration: 089-28195-00373
Reviewer: Sandra Carr
Application Date: July 2, 2009

ELECTROSTATIC OILER:

The electrostatic oiler applies a protective coat to the final product prior to packing and shipping.
There are no particulate emissions from electrostatic oiling, however, there is slight volatility in the oil.

Per the MSDS,

6.1%	volatile by volume

If we assume worse case that all of the oil used in the oiler volatilizes at this rate, then,

2691	mg/m^2, max application rate	(250 mg/ft^2 per facility data sources)
0.0005499	lb/ft^2, max application rate	
350	ft/min, max line speed	
183,960,000	feet, max amount of steel strip possible per year	
50	inches, typical max steel width	
766,500,000	ft^2, max square footage of steel strip per year	
421527.93	lbs, max amount of oil that can be processed per year	
25713.20	lbs of VOC potential	
12.86	**tons/yr of VOC potential**	
2.94	lb VOC/hr	
70.45	lb VOC/day	

TOTALS for electrogalvanizing line:

PM (ton/yr)	VOC (ton/yr)	HAP (ton/yr)
1.8E-05	12.86	3.8E-05

Compliance with 326 IAC 6-3-2: Electrogalvanzing line

$E = 55.0\ P^{0.11} - 40$ Where: E = Rate of emission in pounds per hour; and
P = Process weight in tons per hour.

Electrogalvanizing	$E = [55.0 \times (146^{0.11})] - 40 =$	**55.2**	lb/hr allowable emissions
		241.6	ton/yr allowable emissions

Allowable emissions from the electrogalvanizing line are 56.3 pounds per hour and the potential emissions from the electrogalvanizing line are 6.48 pounds per hour. The source is able to comply without the use of a control.

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT

We Protect Hoosiers and Our Environment.

Mitchell E. Daniels Jr.
Governor

Thomas W. Easterly
Commissioner

100 North Senate Avenue
Indianapolis, Indiana 46204
(317) 232-8603
Toll Free (800) 451-6027
www.idem.IN.gov

SENT VIA U.S. MAIL: CONFIRMED DELIVERY AND SIGNATURE REQUESTED

TO: Kenneth Paxson
Electric Coating Technologies, LLC
4407 Railroad AVenue
East Chicago, Indiana 46312

DATE: September 10, 2009

FROM: Matt Stuckey, Branch Chief
Permits Branch
Office of Air Quality

SUBJECT: Final Decision
Registration
089-28195-00373

Enclosed is the final decision and supporting materials for the air permit application referenced above. Please note that this packet contains the original, signed, permit documents.

The final decision is being sent to you because our records indicate that you are the contact person for this application. However, if you are not the appropriate person within your company to receive this document, please forward it to the correct person.

A copy of the final decision and supporting materials has also been sent via standard mail to:
Mr. Ralph Mora
OAQ Permits Branch Interested Parties List

If you have technical questions regarding the enclosed documents, please contact the Office of Air Quality, Permits Branch at (317) 233-0178, or toll-free at 1-800-451-6027 (ext. 3-0178), and ask to speak to the permit reviewer who prepared the permit. If you think you have received this document in error, please contact Joanne Smiddie-Brush of my staff at 1-800-451-6027 (ext 3-0185), or via e-mail at jbrush@idem.IN.gov.

Final Applicant Cover letter.dot 11/30/07

Mail Code 61-53

IDEM Staff	CDENNY 9/10/2009 Electric Coating Technologies L.L.C. 089-28195-00373 (final)			AFFIX STAMP HERE IF USED AS CERTIFICATE OF MAILING
Name and address of Sender	▶	Indiana Department of Environmental Management Office of Air Quality – Permits Branch 100 N. Senate Indianapolis, IN 46204	Type of Mail: **CERTIFICATE OF MAILING ONLY**	

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1		Kenneth W Paxson Electric Coating Technologies L.L.C. 4407 Railroad Ave East Chicago IN 46312 (Source CAATS) **VIA CONFIRMED DELIVERY**									
2		East Chicago City Council 4525 Indianapolis Blvd East Chicago IN 46312 *(Local Official)*									
3		Gary - Hobart Water Corp 650 Madison St, P.O. Box M486 Gary IN 46401-0486 *(Affected Party)*									
4		Lake County Health Department-Gary 1145 W. 5th Ave Gary IN 46402-1795 *(Health Department)*									
5		WJOB / WZVN Radio 6405 Olcott Ave Hammond IN 46320 *(Affected Party)*									
6		Laurence A. McHugh Barnes & Thornburg 100 North Michigan South Bend IN 46601-1632 *(Affected Party)*									
7		Shawn Sobocinski 3229 E. Atlanta Court Portage IN 46368 *(Affected Party)*									
8		Ms. Carolyn Marsh Lake Michigan Calumet Advisory Council 1804 Oliver St Whiting IN 46394-1725 *(Affected Party)*									
9		Ralph Mora Integrated Enviromental Solutions, Inc. 7550 East Melton Road Gary IN 46403 *(Consultant)*									
10		Mark Coleman 9 Locust Place Ogden Dunes IN 46368 *(Affected Party)*									
11		Mr. Chris Hernandez Pipefitters Association, Local Union 597 8762 Louisiana St., Suite G Merrillville IN 46410 *(Affected Party)*									
12		Craig Hogarth 7901 West Morris Street Indianapolis IN 46231 *(Affected Party)*									
13		Lake County Commissioners 2293 N. Main St, Building A 3rd Floor Crown Point IN 46307 (Local Official)									
14		Anthony Copeland 2006 E. 140th Street East Chicago IN 46312 *(Affected Party)*									
15		Barbara G. Perez 506 Lilac Street East Chicago IN 46312 *(Affected Party)*									

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1		Robert 3733 Parrish Avenue East Chicago IN 46312 (Affected Party)									
2		Ms. Karen Kroczek 8212 Madison Ave Munster IN 46321-1627 *(Affected Party)*									
3		Calumet Township Trustee 35 E 5th Avenue Gary IN 46402 *(Affected Party)*									
4		Joseph Hero 11723 S Oakridge Drive St. John IN 46373 *(Affected Party)*									
5		Gary City Council 401 Broadway # 209 Gary IN 46402 *(Local Official)*									
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